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PRODUCTION OF JET FUELS FROM COAL-DERIVED LIQUIDS

VOL XI - Production of Advanced Endothermic Fuel Blends from Great Plains Gasification Plant Naphtha By-Product Stream

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The U.S. Air Force has an ongoing program to evaluate various endothermic fuels for cooling aircraft structures. The fuels will provide a heat sink by vaporization (latent heat) and endothermic reactions (dehydrogenation) before use as fuel in aircraft engines. Cycloparaffins hold the most promise for use as endothermic fuels.

The U.S. Air Force is also evaluating various feedstock sources of endothermic fuels. The technical feasibility of producing endothermic fuel from the naphtha by-product from Great Plains Gasification Plant in Beulah, North Dakota was evaluated. The capital and operating costs of deriving the fuel from coal naphtha were also estimated.

The coal naphtha from Great Plains was successfully processed to remove sulfur, nitrogen and oxygen contaminants (UOP HD Unibon™ Hydrotreating) and then to saturate aromatic molecules (UOP AH Unibon®). The AH Unibon product was fractionated to yield endothermic fuel candidates with less than 5% aromatics. The major cycloparaffins in the AH Unibon product were cyclohexane and methylcyclohexane. The production of endothermic fuel from the naphtha by-product stream was estimated to be cost competitive with existing technology.

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FOREWORD

In September 1986, the Fuels Branch of the Aero Propulsion Laboratory at Wright-Patterson Air Force Base, OH, commenced an investigation of the potential for production of jet fuel from the liquid by-product streams produced by the gasification of lignite at the Great Plains Gasification Plant located in Buelah, North Dakota. Funding was provided to the U. S. Department of Energy (DOE) Pittsburgh Energy Technology Center (PETC) to administer the experimental portion of this effort. This report details the efforts of Allied-Signal Engineered Materials Research Center. This effort, which was contracted through DOE (DOE Contract Number DE-AC22-87PC79810), examined the technical and economic feasibility of converting the light naphtha stream into advanced, endothermic fuels for high-Mach propulsion systems. Mr. William E. Harrison III was the Air Force Program Manager, Mr. Gary Stiegel was the DOE/PETC Program Manager and Dr. Russell W. Johnson was the Allied-Signal Program Manager.

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1. INTRODUCTION

1.1 Coal as a Fuel Source

The U.S. Department of Energy and the U.S. Air Force have both recognized the need to investigate the use of coal as a source of liquid fuels. The DOE has pursued this goal as an important part of the national energy policy. The USAF has looked at this source to insure the supply of domestically-available fuel and to take advantage of its special properties.

The Great Plains Gasification Plant represents one of the most ambitious projects sponsored by the DOE. The facility produces more than 125 million cubic feet per day of syngas from North Dakota lignite. As a by-product, nearly 5,000 barrels per day of liquids are produced. Although primarily used as boiler fuel at the present time, these materials may be a source of more valuable products.

1.2 Endothermic Fuel Issues

Very high speed aircraft systems planned for the future will require cooling of some components. One source of a heat sink is the fuel. The total cooling capacity of the fuel can be increased if the fuel itself can be caused to undergo an endothermic reaction.

Previous studies have shown that cycloparaffins are good candidates for endothermic fuel systems. These hydrocarbons have physical and chemical properties much like current jet fuels and, therefore, may be handled by conventional fuel systems and engines. Methylcyclohexane (MCH) has been identified as a good

choice for this application. At temperature levels of about 1,000°F and in the presence of a catalyst, MCH will undergo dehydrogenation to yield toluene and hydrogen.

Hydrocarbons with ring structures are potential starting materials for the production of endothermic fuels. Although naphthenes are most desirable, highly aromatic feeds may also be attractive if they can be processed to convert the aromatics to cycloparaffins. The naphtha fraction of the Great Plains naphtha stream is rich in aromatics, which make it an attractive target for the production of endothermic fuels.

The operating economics of the Great Plains Coal Gasification facility at Beulah, North Dakota would be enhanced if high value materials could be made from the contaminated and highly aromatic liquid by-products.

The USAF has identified a need for a new fuel for high speed aircraft. One essential feature of this fuel is that its molecular structure must allow a very selective, dehydrogenation (endothermic) reaction to occur. Cycloparaffins have been identified as leading candidates.

It is possible that a single solution exists for the two different goals of the DOE and USAF. The highly aromatic structure of the coal-derived naphtha components can be selectively converted to cycloparaffins. These cycloparaffins may be good endothermic fuels.

1.3 Technical Approach

The technical approach of this program consists of three main elements:

1. The raw naphtha was treated in a commercial-type, two-step procedure to first remove the sulfur, nitrogen, and oxygen contaminants and then to saturate the aromatic molecules.

2. Catalytic dehydrogenation experiments were conducted to determine the reactivity, stability, and product yield of the treated naphtha and its fractions. The results are compared with pure methylcyclohexane.

3. Process unit investment costs and operating expenses were estimated for the naphtha treating scheme.

Objective

The objective of this project is to evaluate the potential of producing endothermic jet fuel from the naphtha stream yielded as a by-product from the Great Plains Gasification Plant. This evaluation will include:

(a) the technical feasibility of producing a saturated, cycloparaffinic product from the raw naphtha,

(b) determinations of the reactivity and stability of the naphtha stream during endothermic conversion as compared with methylcyclohexane and decalin,

(c) an estimate of the investment and operating costs of producing the saturated product.

Approach

The approach to accomplish the objectives of this program comprises three main elements:

1. naphtha treating to remove contaminants and saturate aromatics,

2. evaluation of the naphtha and its components as endothermic fuel,

3. economic assessment.

The approach in the first element comprises two sequential processing steps using commercially available refining technology. Sulfur, nitrogen, and oxygen contaminants were removed by hydrotreating. The target specification for this step was to reduce the nitrogen content to less than 1 ppm. After contaminant removal, the naphtha was treated using the AH Unibon® process to reduce the total aromatic content to less than 5%. The product was then fractionated into candidate fuels.

The fuel candidates were evaluated for their use as endothermic fuel by subjecting them to catalytic dehydrogenation and then comparing their reactivity, stability, and product distributions with reference endothermic fuels, methylcyclohexane and decalin.

The cost of producing the endothermic fuel from the raw naphtha was estimated using curve-type investment costs and estimates of operating expenses based on commercial experience.

Production and use of endothermic fuels from coal-derived liquids requires the use of noble metal based catalysts such as platinum. The noble metal catalyst is usually impregnated on a support such as alumina. Raw coal liquids contain several impurities that would cause rapid deactivation of noble metal catalysts. These impurities are removed in commercial refineries by utilizing catalytic hydrotreating technology. Sulfur-, nitrogen- and oxygen-containing compounds are reacted with hydrogen in the presence of a catalyst to form hydrogen sulfide, ammonia, and water, which are removed from the product. At the same time olefins are converted to corresponding saturates. Generalized correlations are used by engineering companies to predict approximate hydrotreating process conditions and catalysts. However, confirmation of the estimated process conditions is necessary for an accurate economic analysis.

2. FEEDSTOCK PROCUREMENT AND ANALYSIS

2.1 Procurement

The charge stock for this project was received at Allied-Signal Engineered Materials Research Center on October 12, 1987, in two 55-gallon drums blanketed with nitrogen gas. The drums were placed in cold storage and fitted with piping to allow liquid withdrawal while maintaining a nitrogen blanket.

2.2 Analysis

The analysis for the raw naphtha is summarized in Table 2-1. Only partial analyses were obtained on drum 2 material since the contents from drum 1 were used for pilot plant processing. Great care was exercised in sampling, handling, and analysis of the raw coal naphtha because of its extremely pervasive, noxious odor. The relatively high density indicates a substantial aromatic content for this light naphtha mixture. Sulfur and nitrogen contents of 1.6 wt% and 0.2 wt% respectively, a 61.4 bromine number and the 9.1 diene value are characteristic of liquids derived from thermal treatment of coal. The high concentration of diolefins indicates that two-stage hydrotreating should be used to upgrade the naphtha. The 4.5 wt% oxygen content may not be entirely coal-derived since it includes significant amounts of low boiling solvents such as acetone and butanone. The high concentrations of these components may result from the Rectisol processing of the raw gas. These oxygenates must also be removed during hydrotreating to prevent deactivation of the noble metal, AH Unibon catalyst. Additional analyses indicated that the 108 wt ppm chloride is organic rather than inorganic in nature. Inorganic chloride would be objectionable from a catalyst fouling standpoint. Organic chloride also presents a problem in that special metallurgy may be required under certain conditions for

TABLE 2-1

Raw Naphtha Analysis

		DRUM 1	DRUM 2
GRAVITY, DEGREES API		39.2	40.1
DENSITY, G/ML		0.8299	0.8244
ELEMENTAL ANALYSIS			
CARBON, MASS %		84.2	
HYDROGEN, MASS %		9.8	
SULFUR, MASS %		1.58	1.66
NITROGEN, MASS %		0.20	0.22
OXYGEN, MASS %		4.5	
CHLORINE, MASS PPM		108	
IRON, MASS PPM	1.3		
MANGANESE, MASS PPM	<0.03		
CHROMIUM, MASS PPM	<0.03		
NICKEL, MASS PPM	<0.27		
MOLYBDENUM, MASS PPM	<0.11		
COPPER, MASS PPM	<0.03		
ZINC, MASS PPM	<0.05		
TIN, MASS PPM	<0.53		
LEAD, MASS PPM	<0.53		
CALCIUM, MASS PPM	0.43		
MAGNESIUM, MASS PPM	0.10		
SODIUM, MASS PPM	1.6		
ALUMINUM, MASS PPM	0.16		
VANADIUM, MASS PPM	<0.03		
CADMIUM, MASS PPM	<0.11		
COBALT, MASS PPM	<0.27		
POTASSIUM, MASS PPM	<0.53		
TITANIUM, MASS PPM	0.04		
STONTIUM, MASS PPM	<0.01		
BARIUM, MASS PPM	<0.01		
PHOSPORUS, PPM	<0.53		
DIENE VALUE		9.1	6.8
BROMINE NUMBER		61.4	63.2
HEPTANE INSOL, MASS %		0.01	
MERCAPTAN S, MASS PPM		6200	
ACID NUMBER		N/D	
EXISTENT GUMS, MG/100 ML			
UNWASHED		103.4	
HEPTANE WASHED		36	
POTENTIAL GUMS, MG/100 ML			
UNWASHED		2008	
HEPTANE WASHED		2015	
CARBON RESIDUE ON BOTTOM 10% OF D-86 DISTILLATION, MASS %		0.76	
DISTILLATION (D-86)			
TEMPERATURES IN DEGREES C			
PERCENT DISTILLED (VOL)			
IBP			47
5			53
10			60
25			73
50			85
75			98
90			126
94 (END POINT)			155
SIMULATED DISTILLATION (D-3710)		TEMPERATURES IN DEGREES C	
PERCENT ELUTED (MASS)			
5		35	34
10		53	51
25		83	82
50		85	84
75		113	113
90		134	129
95		151	146
99.5		296	229

commercial units to resist corrosion caused by the hydrochloric acid that is produced. Both existent and potential gums are high, a potential cause of rapid catalyst fouling. The ASTM D-86 distillation shows that 6 volume % of the coal naphtha was non-distillable. High-boiling components generally lead to abnormal carbon formation on the catalyst. The 0.76 wt% carbon residue on the 10% bottoms from distillation is also indicative of high catalyst fouling rates. The presence of high-boiling components is verified by the GC simulated distillations.

Properties of the drum 2 liquid are in reasonable agreement with those from drum 1. However, there may be significant fluctuation in contaminant concentrations during commercial operation.

The GC/MS analysis, summarized in Table 2-2 and Figure 2-1, provides a semi-quantitative component distribution for the coal naphtha. It should be noted that the percentage values given in this analysis are based upon the total ion chromatograph and therefore do not necessarily represent actual concentrations. Aromatics, olefins, diolefins, and paraffin species are predominate. The unidentified 1.3 wt% most likely represent sulfur or oxygenated compounds.

TABLE 2-2

GC/MS Analysis of Raw Coal Naphtha

PEAK NO.	% OF TOTAL	PEAK IDENTIFICATION
1.	4.8	METHANETHIOL & BUTANE
2.	4.5	ACETONE
3.	4.1	PENTANE
4.	1.8	1, 1-DIMETHYL CYCLOPROPANE
5.	1.4	3-PENTEN-1-YNE
6.	1.0	ISOPROPYLENE CYCLOPROPANE
7.	1.5	2-METHYLPENTANE
8.	2.6	2-BUTANONE
9.	1.8	2-METHYLPENTENE
10.	2.8	HEXANE
11.	2.8	C-6 OLEFIN
12.	0.8	C-6 OLEFIN
13.	0.5	C-6 OLEFIN
14.	1.8	METHYLCYCLOPENTADIENE
15.	19.3	BENZENE
16.	0.5	NO ID
17.	0.5	NO ID
18.	1.3	3-METHYL-2-BUTANONE
19.	0.7	CYCLOHEXENE
20.	0.7	3-PENTANONE
21.	0.3	DIMETHYLCYCLOBUTANONE
22.	1.3	HEPTENE
23.	3.8	3-METHYLHEXANE
24.	0.7	HEXA-DIENE-1-OL
25.	0.5	4,4-DIMETHYLCYCLOPENTENE
26.	0.4	2,2,3-TRIMETHYL-1-BUTENE
27.	0.8	METHYLCYCLOHEXANE
28.	0.3	ETHYLCYCLOPENTANE
29.	1.0	3-METHYLHEXATRIENE
30.	22.0	TOLUENE
31.	0.9	3-METHYL THIOPHENE
32.	0.5	2-METHYL HEPTANE
33.	0.3	NO ID
34.	0.7	METHYLHEPTENE
35.	1.2	OCTANE
36.	0.5	DIMETHYL HEXADIENE
37.	0.7	1,3-PROPANEDITHIOL
38.	0.3	C-9 BRANCHED OLEFIN
39.	1.7	ETHYLBENZENE
40.	5.0	M-XYLENE
41.	1.0	O-XYLENE
42.	0.4	NONANE
43.	0.3	ISOPROPYLBENZENE

PEAK AREAS ARE BASED ON MASS SPECTROMETER TOTAL IONIZATION RESPONSE, AND THEREFORE DO NOT NECESSARILY CORRESPOND DIRECTLY TO CONCENTRATION.

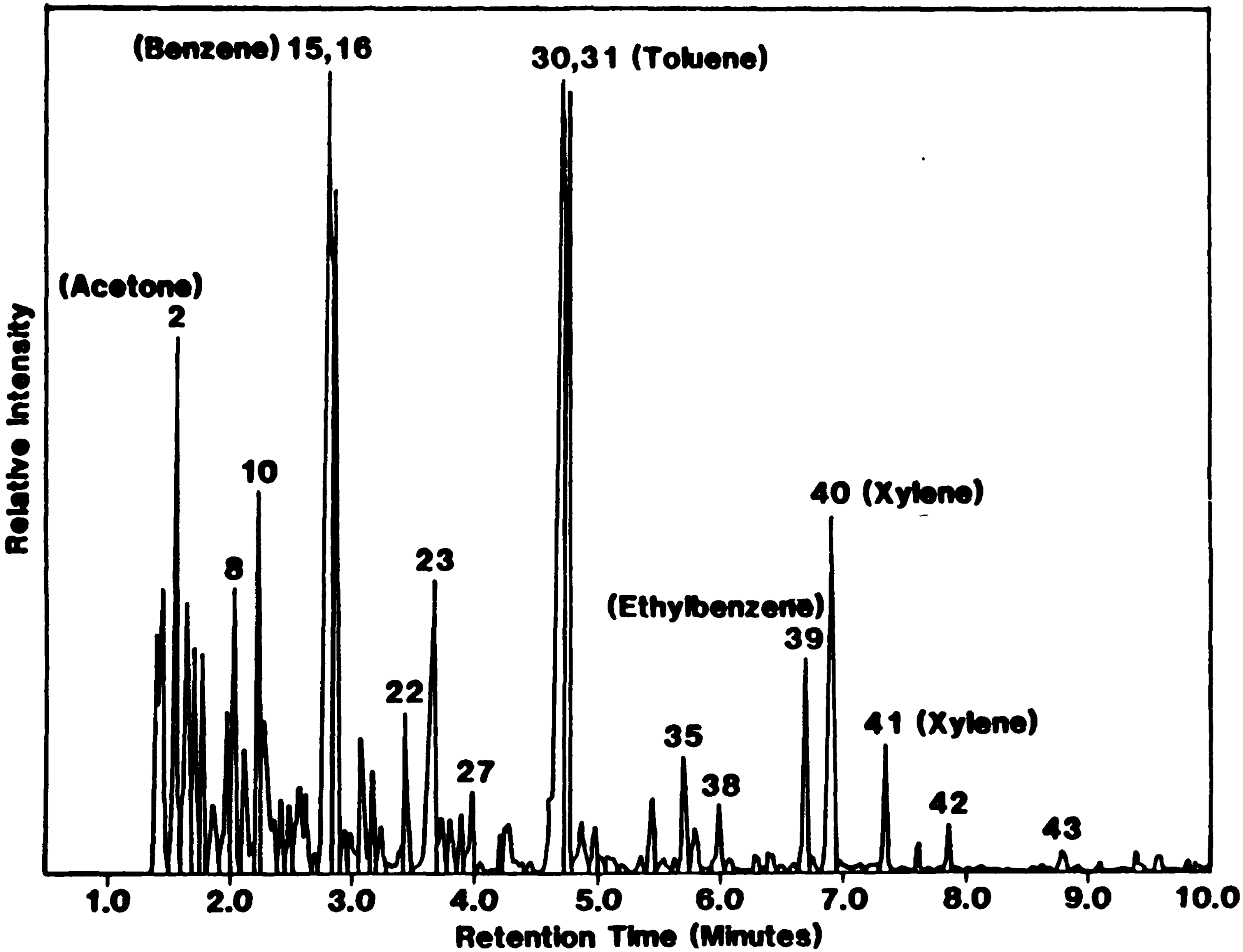


Figure 2-1

GC/MS ANALYSIS OF RAW COAL NAPHTHA

3. NAPHTHA HYDROTREATING

The primary objective of the hydrotreating unit is to reduce the concentration of nitrogen, sulfur, and oxygen-containing components to levels that will not deactivate noble-metal based catalysts. However, the high concentrations of dienes and olefins complicate this task. Conjugated diolefins polymerize at the temperatures required to economically remove heteroatom-containing compounds from the naphtha. To overcome this problem, two-stage hydrotreating is recommended. The first stage of this process operates at relatively low temperature. Under this condition, the diolefin concentration can be reduced to an acceptable level without causing rapid catalyst fouling. The second stage is operated at higher temperatures to achieve high conversion of sulfur and nitrogen containing contaminants.

Two-stage hydrotreating has been used since the early 1950's. This technology is particularly useful for upgrading coke oven light oils and pyrolysis naphthas into sulfur- and nitrogen-free, saturated, high aromatic content liquids. These liquids are separated by extraction and fractionation, yielding high purity benzene. The presence of diolefinic compounds in these raw feeds causes excessive coking in a single-stage reactor preheater operated at temperatures required for desulfurization, nitrogen conversion to ammonia, and olefin saturation. Therefore, two-stage hydrotreating is recommended for all charge stocks with diene values greater than 2. The first-stage reactor saturates diolefins at low temperatures, eliminating coking of the heat exchangers and fired heater on the second stage.

3.1 Experimental Procedure

The hydrotreating process conditions were examined by stage. The first set of experiments used only a single-stage pilot plant configuration so that the conversion kinetics of the first stage could be isolated. After determining the appropriate process conditions for the first-stage operation, two reactors were used in series to evaluate the two-stage process.

The hydrotreating pilot plant is shown in Figures 3-1 and 3-2. The two drums of Great Plains Gasification Plant naphtha were found to contain solid particulates. In order to prevent catalyst bed plugging, a two-stage filtering system employing two, 5 micron filters were installed. A purging system was installed on the pilot plant feed system to control exposure to the feedstock, which has an intense, disagreeable odor.

The naphtha was metered into the reactor inlet along with the hydrogen-rich recycle gas and enough fresh hydrogen to maintain total system pressure. The fresh hydrogen added by demand was metered so that the hydrogen consumption could be determined. The combined charge stock was charged to either a single reactor (first stage) or two reactors in series (two stage).

The reactor effluent was charged to a two-vessel separation train. The existing pilot plant was modified to contact all of the product with a 3 percent potassium hydroxide solution. This basic solution dissolves the hydrogen sulfide that is produced during the catalytic conversion of sulfur-containing components. (The normal configuration of this pilot plant is to charge the first separator liquid discharge to a stripping column.) This modification was made to reduce the loss of light hydrocarbon products that would occur in a

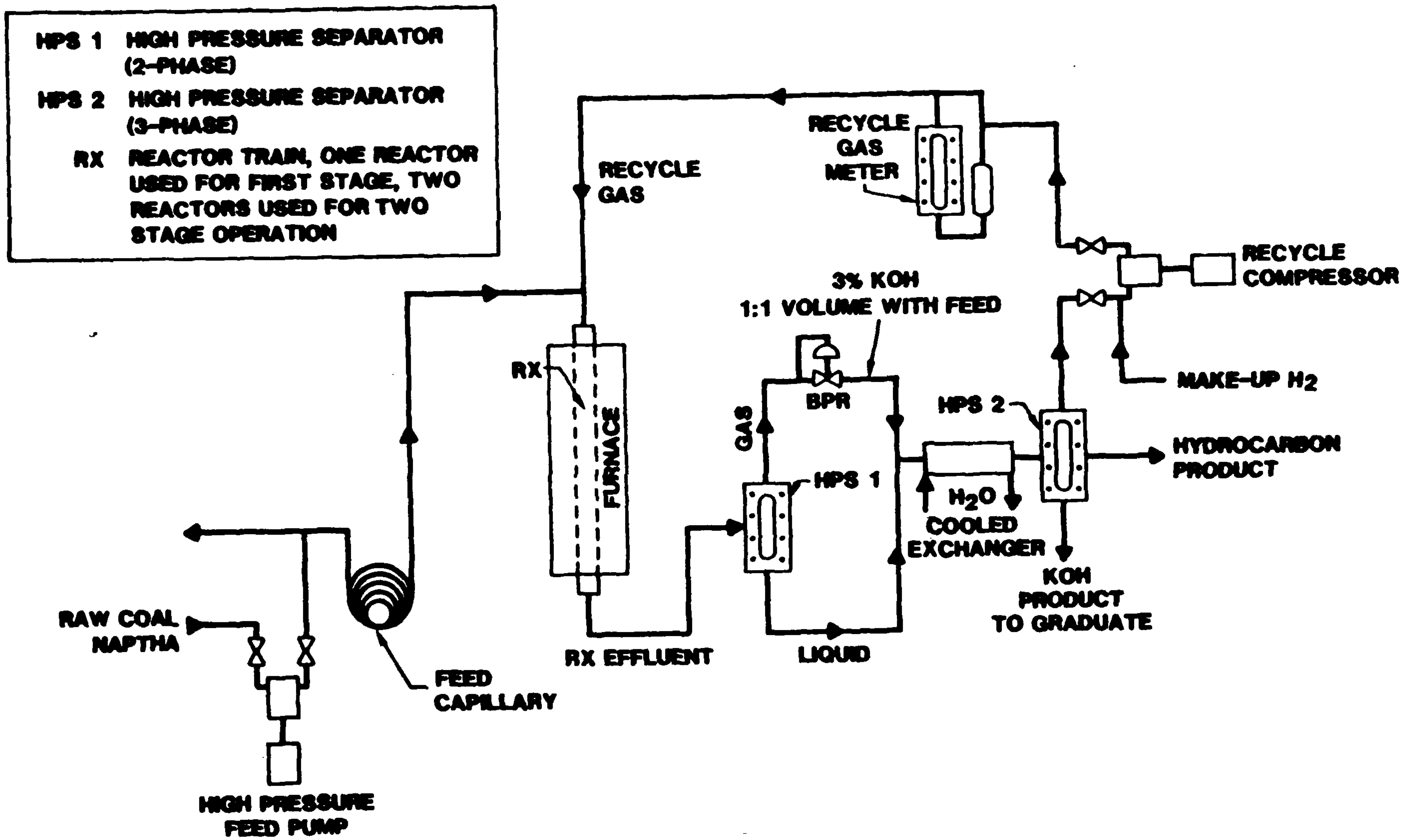


FIGURE 3-1

Coal Naphtha Hydrotreating Pilot Plant

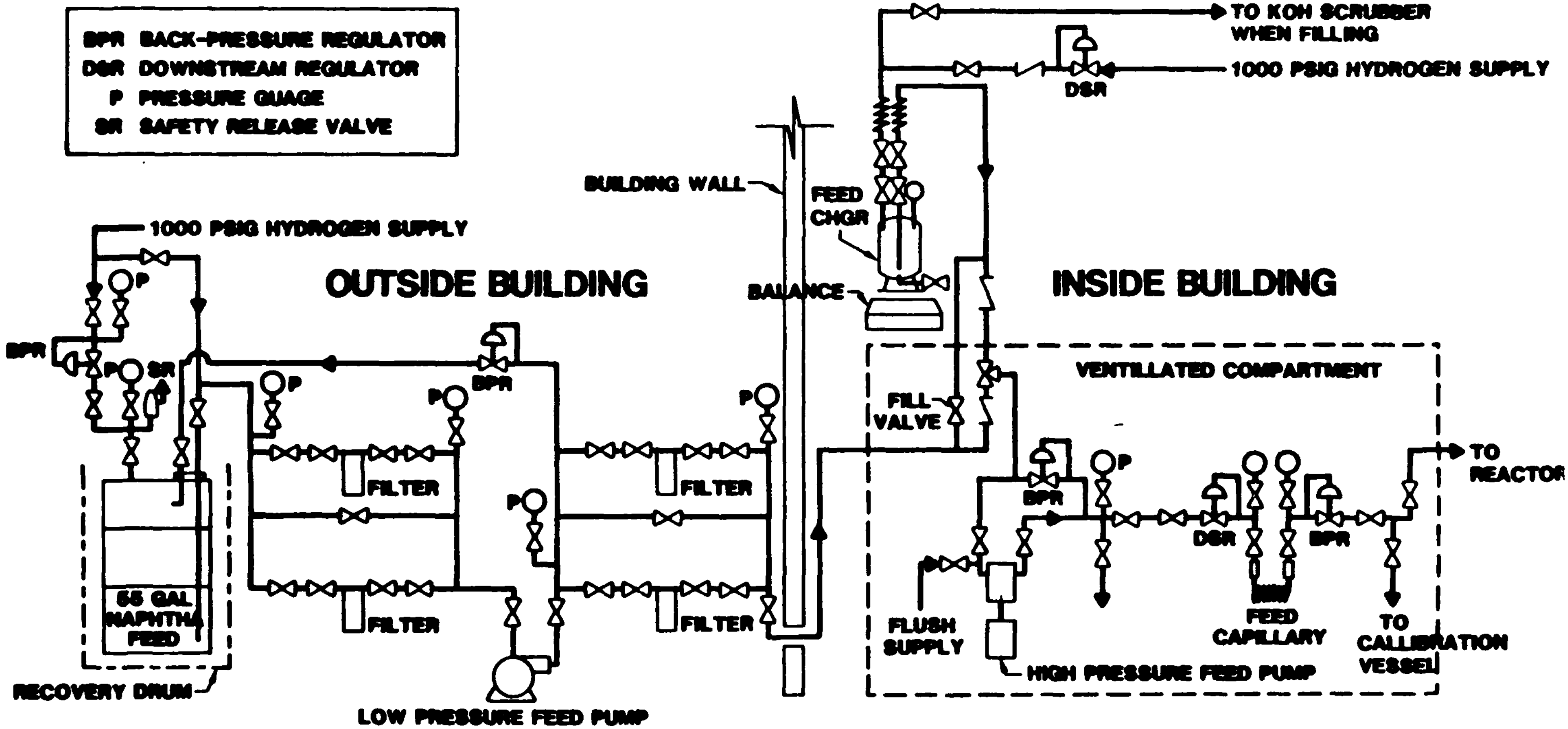


FIGURE 3-2

Coal Naphtha Hydrotreating Plant: Charge Stock Addition Detail

stripping column. The liquid product was weighed to establish a liquid mass yield. A 1 cubic foot per hour (CFH) purge was removed from the recycle gas to control the recycle-gas purity and to determine the recycle gas composition and light hydrocarbon yield.

This raw coal naphtha resembles by-product naphthas from light oils produced by coke oven operations. Coke oven derived naphtha charge stocks have similar sulfur, nitrogen, oxygen, olefin, diolefin and aromatic concentrations. Other commercially-derived hydrotreating charge stocks having analogous characteristics are ethylene pyrolysis by-product liquids, thermal and catalytic cracker naphthas, and direct liquefaction coal liquids. Extensive pilot plant studies and commercial designs have been done on these similar charge stocks.

3.2 First-Stage Hydrotreating

A process variable study was conducted on the Great Plains Gasification Plant naphtha to confirm the predicted conditions based on charge stock analyses.

Process conditions were varied to determine the minimum temperature and maximum space velocity that would reduce the 9.1 Diene Value below 1.0 at 1000 psig. Temperatures were varied from 230°C to 280°C at relative feed rates of 1, 2 and 3. A summary of the process conditions and product analyses is given in Table 3-1. As expected, the lowest diene values were obtained at the lowest feed rates. However, in order to simulate probable commercial conditions, the highest feed rate was employed in the two-stage pilot plant run. A significant degree of desulfurization was observed in the first stage reactor study.

TABLE 3-1 Process Conditions and Product Analyses

Pilot Plant 536 Run 822

Period Number	-	3	5	8	11	14	17
Relative Feed Rate	Charge Stock	1.0	2.0	3.0	3.0	2.0	3.0
Average Catalyst Temperature, °C	-	232	229	232	260	259	278
Pressure, psig	-	1000	1000	1000	1000	1000	1000
LECO Sulfur (HCBN Prod), Mass %	1.58	0.86	1.19	0.94	0.84	0.79	0.53
Bromine Number, gm Br/100 gm	61.4	33.2	48.8	49.7	40.8	36.7	31.6
Coulimetric Nitrogen, Mass ppm	1980	120.0	137.0	149.0	121.5	98.0	442.5
Diene Value	9.1	3.22	10.15	12.36	1.78	2.61	0.79
Existent Gums, mg/mL	103.4	1.2	0.2	1.2	0.2	1.0	0.2
Stability of Gasoline, mg/100 mL		51.0	165.0	93.0	28.0	21.0	10.0

Simulated Distillation (D-3710) Temperatures in Degrees C

Percent Eluted							
5	35	36	37	40	40	37	35
10	53	64	64	68	69	62	57
25	83	83	83	83	83	84	83
50	85	85	85	85	85	86	86
75	113	113	113	113	113	113	113
90	134	125	126	125	126	122	117
95	151	141	141	140	141	141	140
99.5	296	262	258	203	208	216	195

The large number of sulfur, nitrogen, and oxygen-containing compounds present in the raw coal naphtha complicates the kinetic analysis. However, the observed conversion rates are quite consistent with predictions based upon studies with other coal-derived liquids. From other work on coal, shale oil, and tar sands liquids, sulfur removal probably occurs in two consecutive first order reactions and nitrogen follows approximately first to 1.5 order kinetics.

This experiment demonstrates that olefin and diolefin concentrations can be reduced to acceptable levels in the first stage of a hydrotreating unit. It also demonstrates that partial conversion of sulfur-containing components will occur in the first-stage hydrotreating reactor.

3.3 Two-Stage Hydrotreating

A second reactor was placed in service for this portion of the program. The objectives were to verify that the predicted process conditions produce an acceptable product and to produce 50 gallons hydrotreated naphtha product. The entire run was conducted at a constant space velocity. The temperature of the second reactor was varied from 365°C to 395°C as needed to maintain the liquid product sulfur concentration to below six weight parts per million. A detailed process summary is given in Appendix A.

The analytical results are summarized in Table 3-2. These results verify that high conversions of sulfur and nitrogen-containing compounds were achieved. Feed nitrogen was reduced to well below 1 ppm, but sulfur varied from 1-3 ppm. This desulfurization limit may be limited by equilibrium of H_2S and trace olefins at the reactor outlet. In a commercial operation, a lower temperature zone at the end of the reactor train or inter-stage basic scrubbing to remove hydrogen sulfide from the gas phase would be used to further reduce the sulfur concentration of the product.

TABLE 3-2

Analytical Summary for Two-Stage Hydrotreating Run

REFERENCE: PLANT 536 RUN 823

AVERAGE HOURS ON STREAM	24	48	80	112	168	204	264	312
PERIOD NUMBER	3	5	8	11	14	16	18	20
INTERSTAGE SULFUR, MASS %	0.39	0.44	0.09	0.56	0.62	0.61	0.71	0.77
PRODUCT ANALYSIS								
CARBON, MASS %	87.1	85.7	85.5		87.0	85.6	87.2	87.6
HYDROGEN, MASS %	11.0	10.8	10.6	10.9	10.8	10.7	10.9	11.0
SULFUR, MASS PPM	4.3	2.6	2.6	4.9	4.6	7.4	3.0	3.0
NITROGEN, MASS PPM	1.3	0.3	0.3	0.3	0.2	0.1	0.1	0.1
BROMINE NUMBER	0.9	0.8	0.9	0.9	0.9	1.0	1.0	1.0
SIMULATED DISTILLATION (D-3710) TEMPERATURES IN DEGREES C								
PERCENT ELUTED								
5	27	27	36	25	20	21	34	36
10	56	57	58	57	54	54	58	59
25	83	83	83	83	82	82	83	83
50	85	85	85	85	85	85	86	86
75	112	112	113	112	111	112	113	113
90	117	116	117	116	116	120	118	124
95	140	139	140	140	139	140	140	141
99.5	215	203	201	195	202	233	178	271

AVERAGE HOURS ON STREAM	360	408	456	504	552	600	648	696
PERIOD NUMBER	22	24	26	28	30	32	34	36
INTERSTAGE SULFUR, MASS %	0.77	0.73	0.61	0.71	0.94	0.75	0.7	0.79
PRODUCT ANALYSIS								
CARBON, MASS %	88.1	86.2	87.3	87.4	86.1	86.9	86.9	86.6
HYDROGEN, MASS %	11.0	10.8	10.9	10.9	10.9	11.3	11.4	11.5
SULFUR, MASS PPM	3.5	4.4	1.5	1.2	7.6	1.5	2.8	1.5
NITROGEN, MASS PPM	0.1	0.1	0.1	0.1	0.1	0.4	0.2	0.1
BROMINE NUMBER	1.0	1.0	1.0	1.0	1.0	0.9	0.9	0.9
SIMULATED DISTILLATION (D-3710) TEMPERATURES IN DEGREES C								
PERCENT ELUTED								
5	35	34	35	28	35	34	35	36
10	58	58	59	57	58	57	58	58
25	83	83	83	83	83	83	83	83
50	85	85	86	86	86	86	86	85
75	113	113	113	113	113	113	113	113
90	120	120	121	120	120	119	122	119
95	140	140	141	141	140	140	141	140
99.5	194	196	211	212	190	192	272	194

AVERAGE HOURS ON STREAM	792	888	984	1080
PERIOD NUMBER	40	44	48	52
INTERSTAGE SULFUR, MASS %	0.77	0.77		0.94
PRODUCT ANALYSIS				
CARBON, MASS %	86.6	87.0		
HYDROGEN, MASS %	11.3	12.1		
SULFUR, MASS PPM	1.8	1.3	1.6	2.4
NITROGEN, MASS PPM	0.1	0.3	0.1	0.1
BROMINE NUMBER	1.0	1.0	1.0	1.0
SIMULATED DISTILLATION (D-3710) TEMPERATURES IN DEGREES C				
PERCENT ELUTED				
5	35	35	35	34
10	58	57	59	57
25	83	83	82	82
50	85	85	85	84
75	112	112	112	112
90	125	121	121	117
95	141	140	140	139
99.5	328	254	204	195

The two-stage hydrotreating run was continued for a time sufficient for the production of approximately 50 gallons of product. The individual hydrocarbon products from the two-stage pilot plant run (Pilot Plant 638, Run 823) were blended into a 55-gallon drum, which was labeled 5740-55. The analysis of this blend is summarized in Tables 3-3 and 3-4. This blend will be used as a charge stock for the preparation of endothermic fuel candidates during the next part of the program.

A semi-quantitative GC/MS analysis of the hydrotreated naphtha blend is shown in Figure 3-3. Significant cyclohexane and methylcyclohexane concentrations indicate that partial hydrogenation of benzene and toluene occurred during hydrotreating. The area-percent-based concentrations from the GC/MS analysis are summarized in Table 3-5. These values should be regarded as only semi-quantitative because the sensitivity coefficients may vary substantially. The quantitative hydrocarbon distribution obtained by GC analysis given in Table 3-4 shows the following yield structure: aromatics, 60.2%; paraffins, 22.4%; and naphthenes, 18.1%.

The product distribution for a typical period shows a yield corresponding to 1.7% hydrogen sulfide, 5.1% water, 91% liquid product, and 2.1% hydrocarbon gas.

Two-stage hydrotreating was found to be effective in reducing the hetero-compounds, diolefins, and olefins in the raw coal naphtha, producing a saturated liquid product suitable for further processing with noble metal catalysts.

TABLE 3-3

Analysis of Hydrotreated Naphtha Blend

REFERENCE 5740-55	
ELEMENTAL ANALYSIS	
CARBON, MASS %	86.7
HYDROGEN, MASS %	11.1
SULFUR, MASS PPM	2.6
NITROGEN, MASS PPM	0.2
OXYGEN, WT %	>0.1
GRAVITY, DEGREES API	45.3
DENSITY, G/ML	0.8003
WATER, MASS PPM	44
DISTILLATION (D-86)	
TEMPERATURES IN DEGREES C	
PERCENT ELUTED (VOL)	
1	51
5	60
10	67
25	75
50	82
75	92
90	111
95	131
FBP (96.0)	150

SIMULATED DISTILLATION (D-3710)	TEMPERATURES IN DEGREES C
PERCENT ELUTED (MASS)	
5	35
10	57
25	83
50	86
75	114
90	126
95	141
99.5	212

TABLE 3-4

Hydrocarbon Analysis of Hydrotreated Naphtha

SAMPLE IDENTIFICATION: 224
REFERENCE: 5740-55

DESCRIPTION: P536 R823
B5740 55

AROMATICS	MASS %	LV%
BENZENE	40.9	36.9
TOLUENE	15.0	13.7
ETHYLBENZENE	0.8	0.7
P-XYLENE	0.6	0.6
M-XYLENE	0.5	0.3
O-XYLENE	0.5	0.5
CUMENE	0.0	0.0
N-PROPYLBENZENE	0.0	0.0
1-METHYL-4-ETHYLBENZENE	0.2	0.2
1-METHYL-3-ETHYLBENZENE	0.4	0.3
TERT-BUTYLBENZENE	0.0	0.0
ISOBUTYLBENZENE	0.0	0.0
1,3,5-TRIMETHYLBENZENE	0.1	0.1
SEC-BUTYLBENZENE	0.0	0.0
STYRENE	0.0	0.0
1-METHYL-2-ETHYLBENZENE	0.1	0.1
1-METHYL-3-ISOPROPYLBENZENE	0.0	0.0
1-METHYL-4-ISOPROPYLBENZENE	0.0	0.0
1,2,4-TRIMETHYLBENZENE	0.0	0.0
1,3-DIMETHYLBENZENE	0.0	0.0
1-METHYL-2-ISOPROPYLBENZENE	0.0	0.0
1-METHYL-3-N-PROPYLBENZENE	0.0	0.0
1-METHYL-4-N-PROPYLBENZENE	0.0	0.0
1,4-DIETHYLBENZENE	0.0	0.0
N-BUTYLBENZENE	0.0	0.0
1,3-DIMETHYL-5-ETHYLBENZENE	0.0	0.0
1,2-DIETHYLBENZENE	0.0	0.0
1-METHYL-2-N-PROPYLBENZENE	0.0	0.0
1,2,3-TRIMETHYLBENZENE	0.0	0.0
1,4-DIMETHYL-2-ETHYLBENZENE	0.0	0.0
1,3-DIMETHYL-4-ETHYLBENZENE	0.0	0.0
1,2-DIMETHYL-4-ETHYLBENZENE	0.0	0.0
INDANE	0.1	0.1
1,3-DIMETHYL-2-ETHYLBENZENE	0.0	0.0
1,2-DIMETHYL-3-ETHYLBENZENE	0.0	0.0
1,2,4,5-TETRAMETHYLBENZENE	0.0	0.0
1,2,3,5-TETRAMETHYLBENZENE	0.0	0.0
1,2,3,4-TETRAMETHYLBENZENE	0.0	0.0
C11+ AROMATICS	0.0	0.0
TOTAL AROMATICS:	60.2	54.5

TABLE 3-4

Hydrocarbon Analysis of Hydrotreated Naphtha (Continued)

PARAFFINS AND NAPHTHENES

	MASS %	LV %
PROPANE	0.5	0.8
ISOBUTANE	0.1	0.2
n-BUTANE	1.9	2.6
ISO-PENTANE	2.2	2.7
n-PENTANE	3.0	3.9
CYCLOPENTANE	1.6	1.7
C_6 ISOPARAFFINS	3.1	3.8
n-HEXANE	3.7	4.4
METHYLCYCLOPENTANE	3.6	3.8
CYCLOHEXANE	3.1	3.2
C_7 ISOPARAFFINS	1.5	1.7
n-HEPTANE	2.9	3.4
C_7 CYCLOPENTANES	3.0	3.1
METHYLCYCLOHEXANE	2.1	2.2
C_8 ISOPARAFFINS	0.9	1.0
n-OCTANE	1.3	1.5
C_8 CYCLOPENTANES	1.2	1.2
C_8 CYCLOHEXANES	1.1	1.2
C_9 NAPHTHENES	1.1	1.1
C_9 PARAFFINS	0.8	0.9
C_{10} NAPHTHENES	0.3	0.3
C_{10} PARAFFINS	0.3	0.3
C_{11} NAPHTHENES	0.1	0.1
C_{11} PARAFFINS	0.1	0.1
TOTAL PARAFFINS	22.4	27.4
TOTAL NAPHTHENES	17.4	18.1

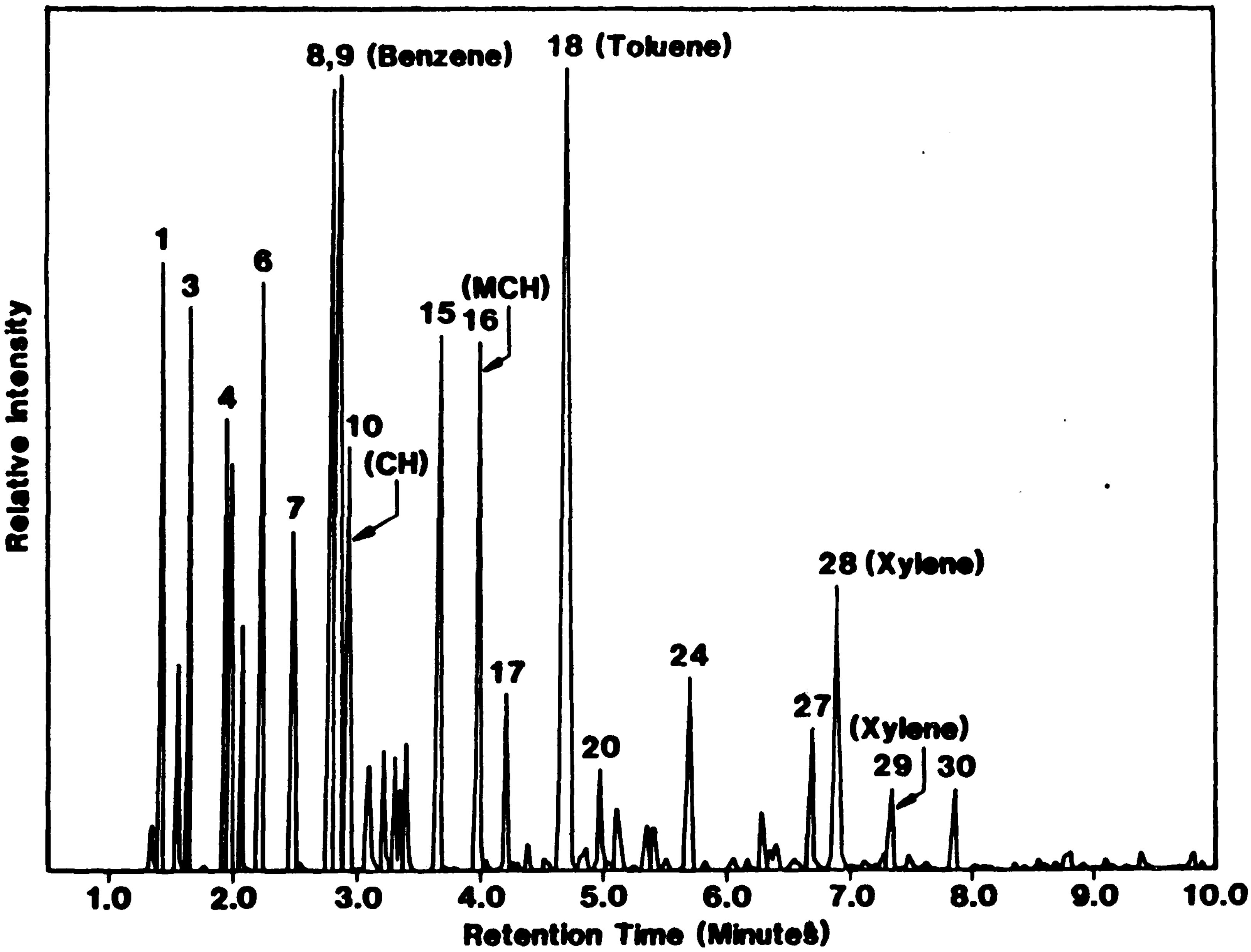


FIGURE 3-3

GC/MS ANALYSIS OF THE HYDROTREATED COAL NAPHTHA

TABLE 3-5

Hydrotreated Naphtha

PEAK NO.	% OF TOTAL	PEAK IDENTIFICATION
1.	4.2	BUTANE
2.	1.5	1-METHYL-2-PROPEN-1-OL
3.	3.9	PENTANE
4.	3.4	CYCLOPENTANE
5.	.8	C 6 PARAFFIN
6.	4.3	3-METHYL PENTANE
7.	4.5	C 6 OLEFIN
8.	12.1	BENZENE
9.	10.0	BENZENE
10.	4.5	CYCLOHEXANE
11.	1.4	DIMETHYLPENTANE
12.	1.0	METHYLHEXANE
13.	1.5	DIMETHYLCYCLOPENTANE
14.	1.0	DIMETHYLCYCLOPENTANE
15.	5.5	HEPTANE
16.	4.5	METHYLCYCLOHEXANE
17.	1.4	ETHYLCYCLOPENTANE
18.	18.1	TOLUENE
19.	0.4	ETHYLMETHYLPENTANE
20.	0.8	2-METHYLHEPTANE
21.	0.8	DIMETHYLCYCLOHEXANE
22.	0.5	ETHYLMETHYLCYCLOPENTANE
23.	0.8	ETHYLMETHYLCYCLOPENTANE
24.	2.3	OCTANE
25.	0.5	DIMETHYLHEXANE
26.	0.5	TRIMETHYLCYCLOHEXANE
27.	1.5	ETHYLBENZENE
28.	4.0	X-XYLENE
29.	0.3	O-XYLENE
30.	0.3	NONANE

CYCLOPENTANES 8.8%

CYCLOHEXANES 9.5%

PEAK AREAS ARE BASED ON MASS SPECTROMETER TOTAL IONIZATION RESPONSE, AND THEREFORE DO NOT NECESSARILY CORRESPOND DIRECTLY TO CONCENTRATION.

4. AROMATIC HYDROGENATION

In order to produce an endothermic fuel capable of undergoing highly endothermic reactions to provide cooling capacity for high speed flight, it is necessary to convert the aromatic components of the hydrotreated coal naphtha into cycloalkanes (naphthenes). This is accomplished by the catalytic, selective, addition of hydrogen to the aromatic ring systems using a supported platinum catalyst at elevated temperature and pressure.

Aromatics saturation technology is utilized on a commercial scale throughout the world for the following purposes:

1. Convert aromatics in diesel fuels to corresponding cyclic saturates for cetane number improvement.

2. Saturate aromatics in kerosine fractions to provide superior jet fuel blending components.

3. Saturate low concentrations of aromatics in normal paraffin extracts for food grade quality.

The objectives of the aromatic saturation task were three-fold:

1. Obtain 99% conversion of aromatics to corresponding naphthenes.

2. Produce 25 gallons of saturated product to be fractionated into cuts containing specific naphthenic compounds. These fractions will be evaluated as endothermic fuel candidates.

3. Provide accurate yield estimate data for cost assessment.

4.1 Experimental Procedure

The pilot plant configuration employed in this work is summarized in Figure 4-1. The charge stock was treated with a reactive, high-surface-area, sodium/alumina guard bed before the reactor to remove any residual water and sulfur compounds. This procedure is not necessary in commercial plants, where a more complete removal of water and conversion of sulfur-containing compounds would be established. The reactor effluent was cooled and charged to a high pressure separator to disengage the hydrogen-rich recycle gas from the liquid product. Approximately 75% of the cool, liquid product was recycled to the reactor inlet to control the temperature increase caused by the high heat of reaction generated by the saturation of aromatics. Also, the catalyst bed was diluted with inert alpha alumina granules to improve heat transfer characteristics. An on-line gas chromatograph provided rapid product analyses for benzene, toluene and xylenes concentrations. The hydrocarbon product was charged to a debutanizer column to remove trace amounts of light hydrocarbon gas and to stabilize the liquid product.

4.2 Process Variable Study

The process variable study was conducted to establish the proper reactor size and reaction conditions for this task. A simulated commercial charge stock was prepared by diluting 1 volume of the two-stage hydrotreating product from the production run with 4 volumes of product from the aromatic hydrogenation production run described in section 4.3. The simulated commercial charge stock was used so that the most accurate estimate could be made without the need to build up a steady-state liquid recycle stream.

FIGURE 4-1

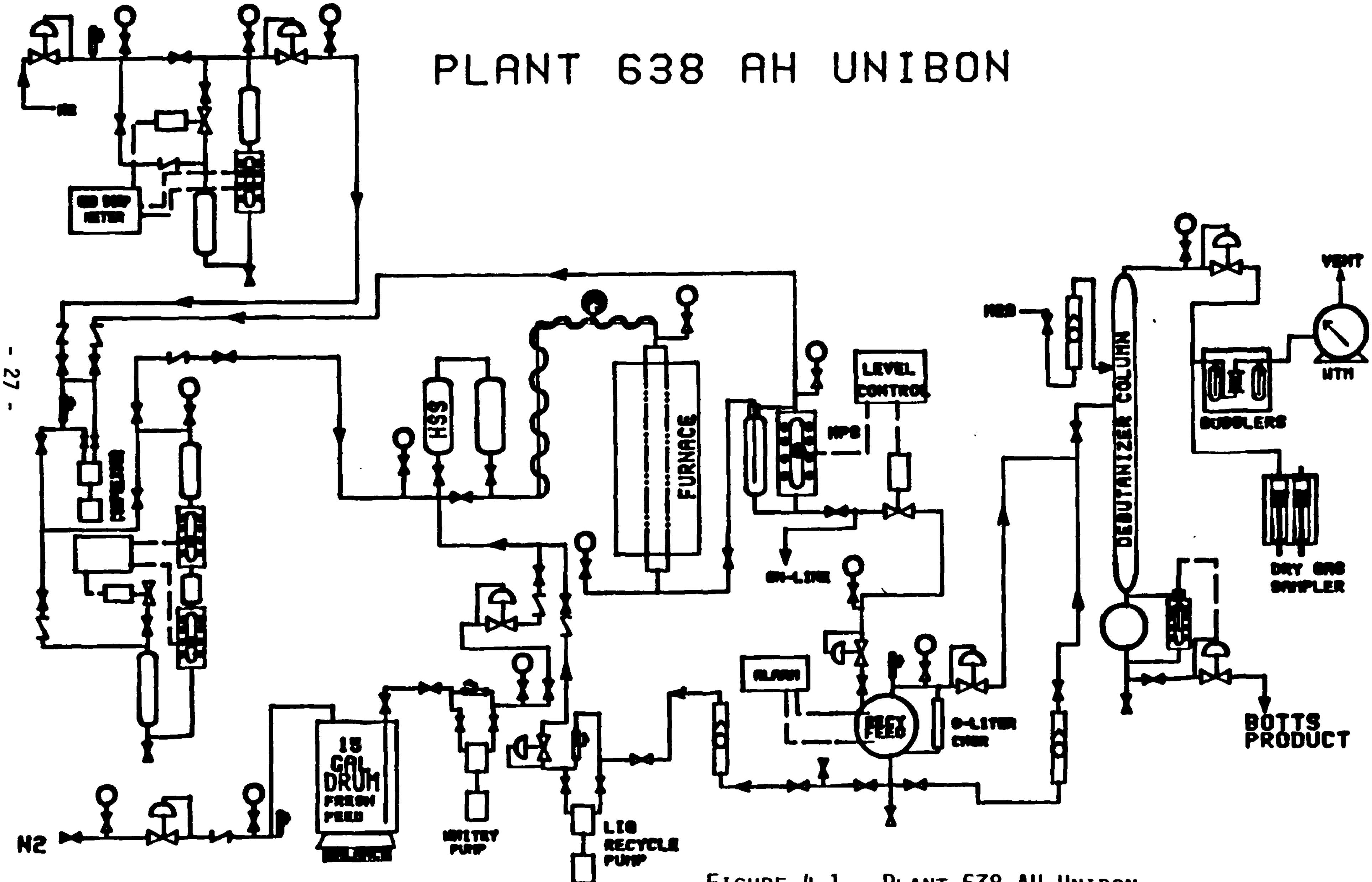


FIGURE 4-1 PLANT 638 AH UNIBON

The results from this experiment are summarized in Table 4-1 and Figures 4-2 through 4-4. The variable study was conducted using temperatures from 65-177°C, pressures from 500-800 psig, and a constant 3,000 SCF/B gas recycle rate.

The plots of product benzene and toluene concentrations shown in Figures 4-2 and 4-3 show that hydrogenation proceeded rapidly, attaining virtually complete removal at 120°C. The reaction was found to proceed very quickly at all of the conditions surveyed.

The measured hydrogen consumption is compared to the value calculated based upon saturation of the aromatic rings in Figure 4-4. The higher value for the measured hydrogen consumption is caused by some side reactions, solubility, and the hydrogenation of higher molecular weight aromatics.

Although xylene conversion was apparently incomplete, these results are uncertain because of the low xylene concentration in the fuel.

Results of the process variable study indicate that:

1. High conversion of aromatic compounds to the saturated homologues can be achieved at temperatures as low as 120°C.

2. Commercially attractive space velocities can be employed for this purpose.

Table 4-1

SUMMARY OF COAL NAPHTHA VARIABLE STUDY

Plant 638 Run #746

Feed: Hydrotreated Coal Naphtha Blend

Charge Stock Analysis

Benzene	9.8 mass %
Toluene	3.4 mass %
p+m-Xylene	0.091 mass %
o-Xylene	0.079 mass %

Period	1	2	3	4	5	6	7
Relative Feed Rate	1.00	0.98	1.00	0.50	0.49	0.50	1.03
Block Temp, °C	66	120.5	149	65.5	122.5	176	74
Cat. Outlet Temp, °C	69	121	146.5	67	121.5	177	68
Mass Balance, %	101	100	100	111	101	96	98
Pressure, psig	500	495	497.5	800	797.5	800	805
GC Analysis							
Benzene	2.980	0.000	0.000	3.312	0.081	0.000	1.498
Toluene	1.130	0.000	0.000	0.457	0.017	0.037	0.604
p+m-Xylene	0.133	0.177	0.165	0.073	0.137	0.190	0.156
o-Xylene	0.064	0.081	0.091	0.049	0.071	0.099	0.084
Liq. In/Out							
Total Feed, grams	160	157	160	80	78	79	165
Liq. Prod., grams	164	159	160	92	80	79	164

Table 4-1 continued

SUMMARY OF COAL NAPHTHA VARIABLE STUDY

Plant 638 Run #746

Feed: Hydrotreated Coal Naphtha Blend

Charge Stock Analysis

Benzene	9.8 mass %
Toluene	3.4 mass %
p+m-Xylene	0.091 mass %
o-Xylene	0.079 mass %

Period	8	9	10	11	12	13	14	15
Relative Feed Rate	0.98	1.15	1.05	1.45	1.50	1.62	1.54	1.50
Block Temp, °C	93	121	148.5	178.5	66	93	121	149.5
Cat. Outlet Temp, °C	98.5	125	143.5	170	72	106.5	127.5	152
Mass Balance, %	92	96	99	103	92	97	101	98
Pressure, psig	800	800	800	805	795	800	800	797.5

GC Analysis

Benzene	0.222	0.000	0.000	0.000	5.923	0.755	0.035	0.028
Toluene	0.137	0.000	0.000	0.000	2.101	0.340	0.028	0.063
p+m-Xylene	0.195	0.188	0.184	0.191	0.121	0.158	0.100	0.100
o-Xylene	0.081	0.096	0.082	0.094	0.050	0.069	0.028	0.028

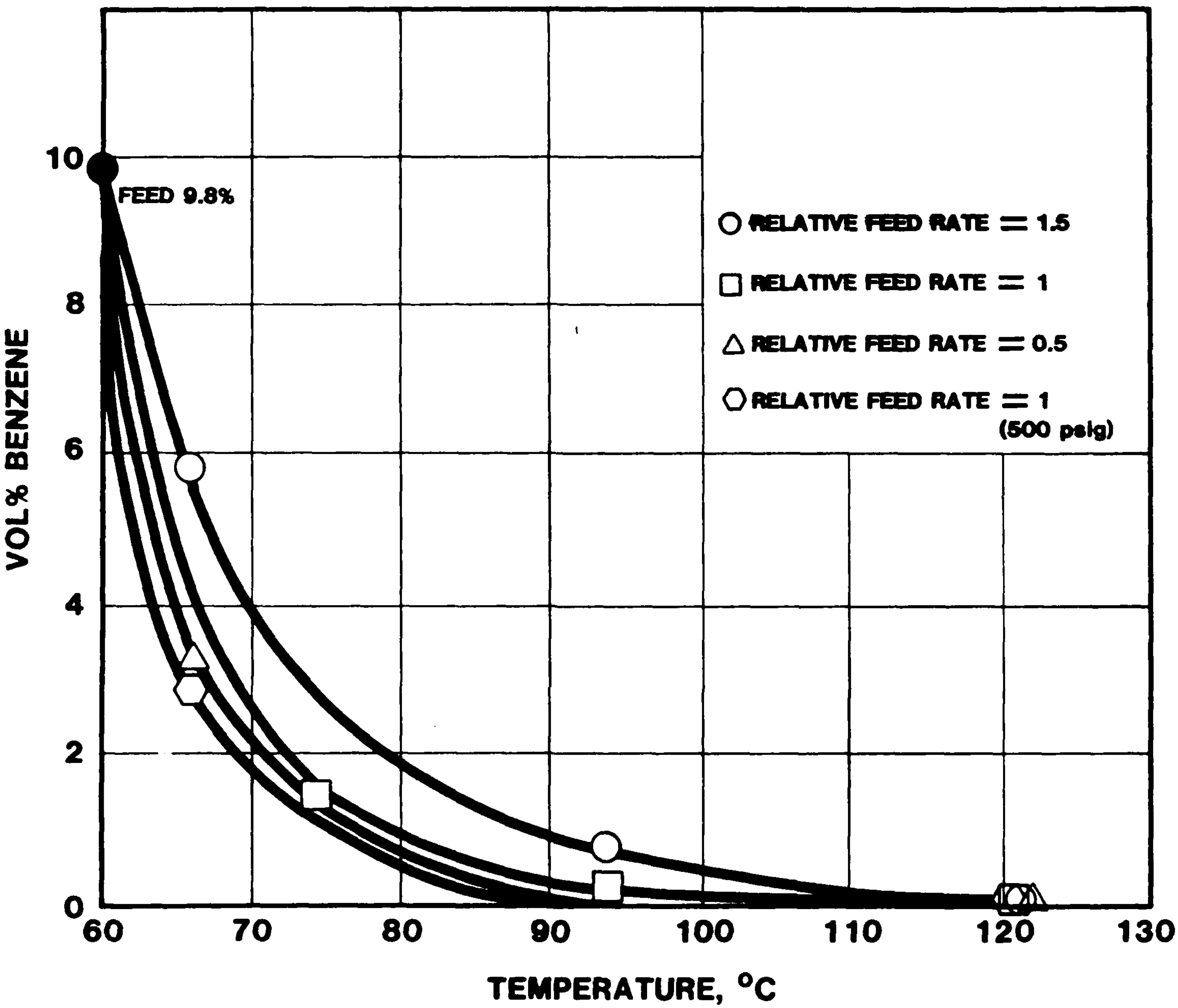


FIGURE 4-2

BENZENE HYDROGENATION CONVERSION
800 psig

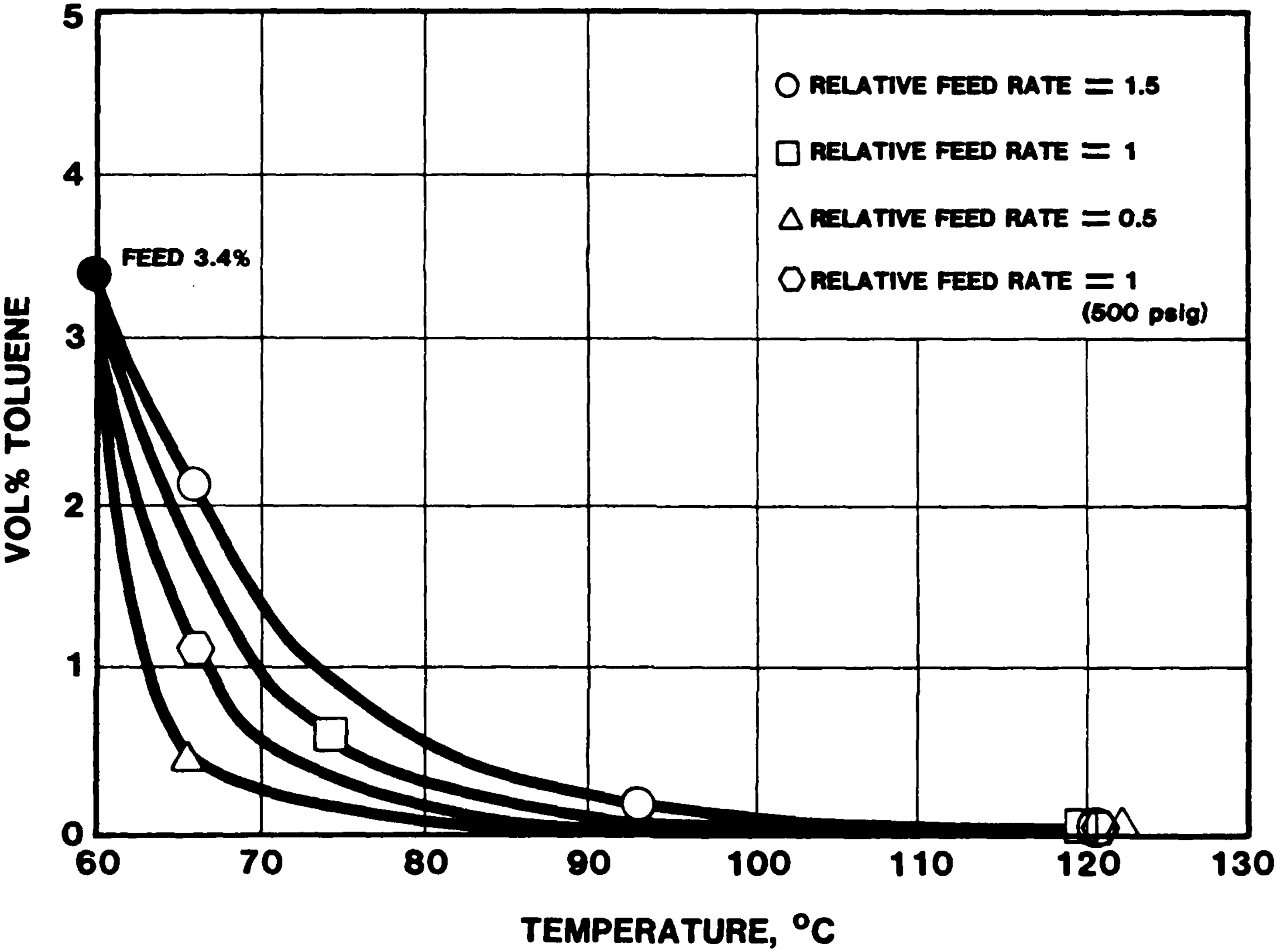


FIGURE 4-3

TOLUENE HYDROGENATION CONVERSION
800 psig

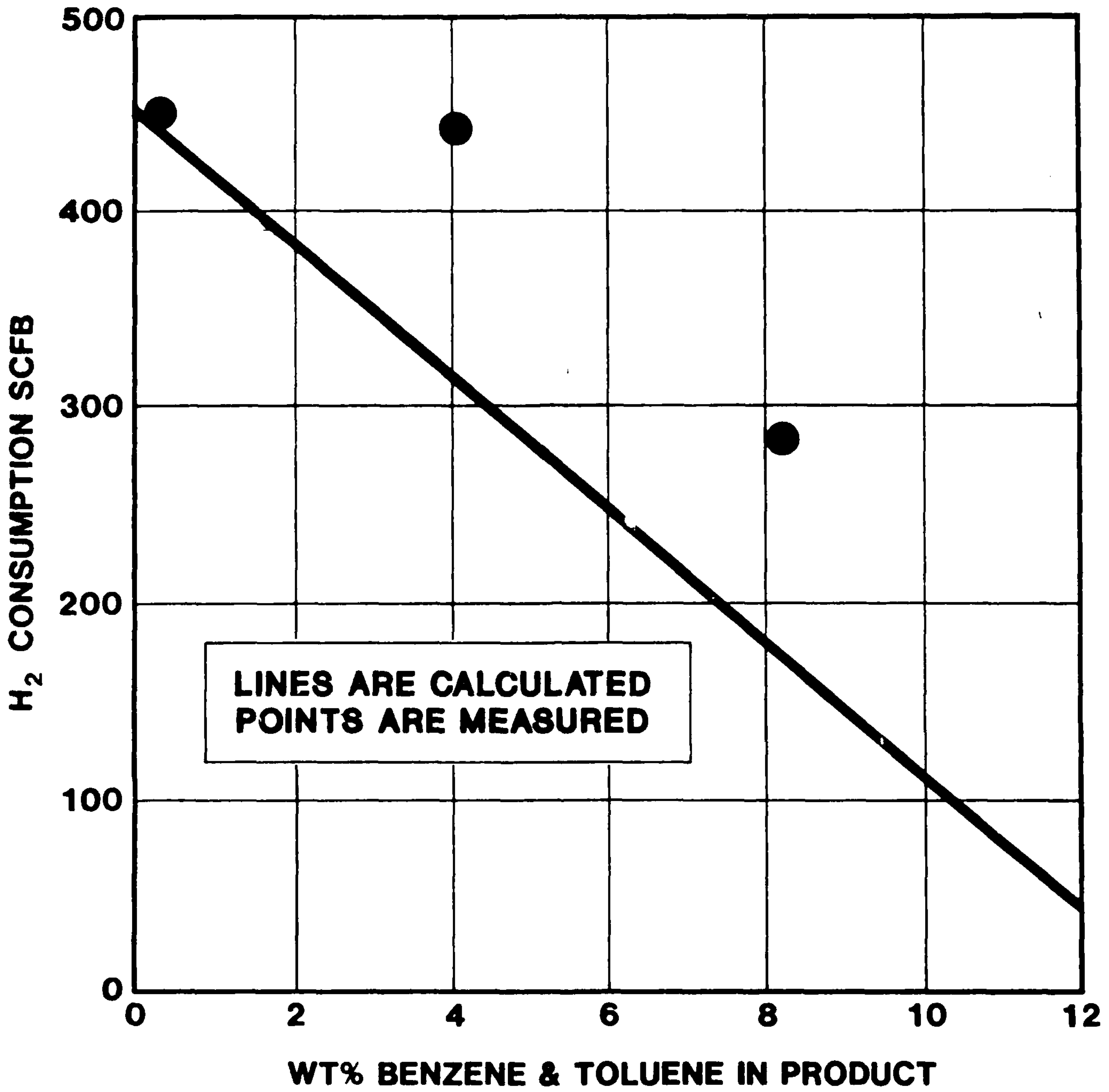


FIGURE 4-4

HYDROGEN CONSUMPTION IN AH UNIBON PROCESS VARIABLE STUDY

4.3 Production Run

The objective of this subtask was to produce 25 gallons of a highly naphthenic naphtha to be used for subsequent fractionation into endothermic fuel candidates.

A laboratory analysis of the liquid product is given in Table 4-2.

Results of the production run are shown in Figure 4-5 and in Appendix A. On-line gas chromatography analytical instrumentation was employed to track the benzene and toluene concentrations in the product. As reactor temperature was increased, total aromatics contents decreased, reaching less than 1% at 320°C. Hydrogen consumption averaged 2,000 SCF/B.

A typical analysis provided by the on-line GC is shown in Table 4-3. Benzene and toluene conversions were 99%+. C_{8+} aromatics (less than 5 mass-% in the feed) conversion was about 94%. In a later, separate operation, mixed xylenes were processed in the same pilot plant unit. High conversions were obtained at a temperature of 375°C.

Hydrogen purity of the recycled gas was exceptionally high as shown in Table 4-3. A debutanizer overhead gas analysis given in Table 4-5 shows that a small amount of C_3-C_5 hydrocarbons retained in the liquid from two-stage hydrotreating was stripped out in the AH operation.

Additional gas chromatography analyses on the individual period samples run in the laboratory are given in Appendix A.

TABLE 4-2

Saturated Product

EMRC Research Center
Gas Chromatography Laboratory Des Plaines, Illinois

Plant #638 Run #744 Period #17

UOP 690 C_{8-}

Component	Mass %
IC5	0.9
NC5	2.6
CP	1.4
2.3DMC4	0.3
2MC5	1.7
3MC5	0.9
NC6	3.5
MCP	3.5
Cyclohexane	49.5
2MC6	0.4
2.3DMC5	0.3
1.1DMCP	0.1
3MC6	0.6
1C3DMCP	0.4
1T3DMCP	0.4
1T2DMCP	0.8
NC7	2.8
MCH + 1C2DMCP	18.4
ECP	0.8
1T2C4TMCP	0.2
1T2C3TMCP	0.1
2M3EC5	0.2
2MC7	0.4
4MC7	0.1
3MC7	0.1
3EC6 + 1C3DMCH + 1C2T3TMCP	1.5
1T4DMCH	0.5
1MT3ECP	0.2
1MC3ECP	0.2
1MT2ECP	0.2
1T2DMCH	0.5
NC8 + C1.4 + T1.3DMCH	2.0
IC3CP	0.1
1C2DMCH	0.2
ECH + NC3CP	1.2
HEAVIES	3.0
TOTAL	100.0

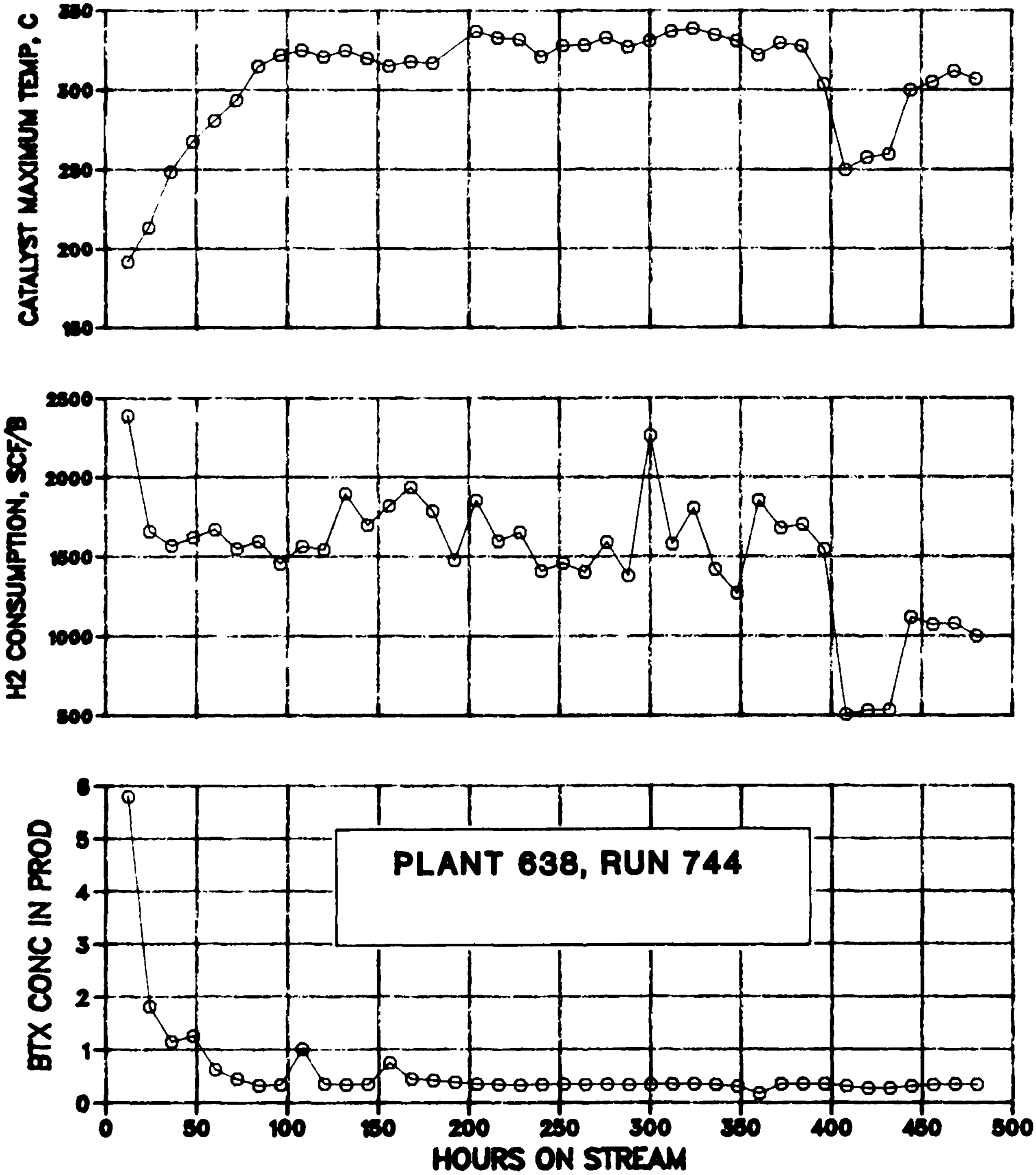


FIGURE 4-5
AROMATICS SATURATION PRODUCTION SUMMARY

TABLE 4-3

Typical On-Line Chromatogram

TABLE I

PROCESSED DATA FILE: P25152 ON CRN 22
MAY 11, 1988 12:15:29
REPORT: 1852 CHANNEL: 25 # PEAKS: -58 PLANT 6 3 8 LIQUID

PEAK	RT	RTM	FACTOR	AREA		MASS-%	NAME
1	3.75	3.75	1.00000	647	BB	.297	C3
2	3.88	3.88	1.00000	209	BV	.096	IC4
3	3.98	3.98	1.00000	3130	VB	1.435	NC4
4	4.32	4.32	1.00000	4021	BV	1.844	IC5
5	4.48	4.48	1.00000	5963	VB	2.734	NC5
6	5.14	5.14	1.00000	7278	BV	3.337	CP+23DMB+2MP
7	5.33	5.34	1.00000	2066	VB	.947	3MP
8	5.56	-5.56	1.00000	7377	BB	3.382	#NC6
9	6.12	6.12	1.00000	7478	BB	3.429	MCP
10	6.90	6.90	1.00000	101902	BV	46.725	CYCLOHEXANE
11	7.03	0.00	1.00000	3756	VV	1.722	
12	7.18	0.00	1.00000	1962	VB	.899	
13	7.47	0.00	1.00000	900	BV	.413	
14	7.56	0.00	1.00000	814	VV	.373	
15	7.64	0.00	1.00000	1800	VB	.825	
16	7.86	-7.86	1.00000	5807	BB	2.663	#NC7
17	8.82	8.82	1.00000	39033	BV	17.898	MCH
18	9.18	0.00	1.00000	1780	VB	.816	
19	9.49	0.00	1.00000	298	BB	.137	
20	9.79	0.00	1.00000	247	BB	.113	
21	10.28	10.19	.90800	58	BV	.024	TOLUENE
22	10.39	0.00	1.00000	202	VV	.092	
23	10.49	0.00	1.00000	1273	VV	.584	
24	10.86	0.00	1.00000	302	VV	.139	
25	11.02	0.00	1.00000	59	VB	.027	
26	11.21	11.22	1.00000	3007	BV	1.379	DMCH
27	11.29	11.27	1.00000	1321	VV	.606	DMCH
28	11.61	0.00	1.00000	559	VV	.256	
29	11.75	11.76	1.00000	998	VV	.458	DMCH
30	11.97	-11.97	1.00000	3830	VV	1.756	#NC8+DMCH
31	12.25	12.22	1.00000	1493	VV	.685	DMCH
32	12.48	0.00	1.00000	131	VB	.060	
33	12.80	0.00	1.00000	110	BB	.051	
34	13.05	12.99	1.00000	802	BV	.368	DMCH
35	13.17	13.17	1.00000	2336	VV	1.071	ECH
36	13.33	0.00	1.00000	413	VV	.189	
37	13.42	0.00	1.00000	174	VV	.080	
38	13.49	0.00	1.00000	160	VB	.073	
39	13.65	13.66	1.00000	92	BB	.042	ETHYLBENZENE+UNK
40	13.82	13.90	1.00000	417	BV	.191	P+M-XYLENE+UNK
41	14.01	0.00	1.00000	146	VV	.067	
42	14.21	0.00	1.00000	304	VB	.139	
43	14.42	14.52	1.00000	164	BV	.075	O-XYLENE+UNK
44	14.62	0.00	1.00000	209	VV	.096	
45	14.70	0.00	1.00000	291	VV	.133	
46	14.76	0.00	1.00000	308	VV	.141	
47	14.91	14.90	1.00000	865	VV	.396	
48	15.18	0.00	1.00000	337	VB	.155	
49	15.49	0.00	1.00000	169	BB	.078	
50	15.72	0.00	1.00000	317	BB	.145	
51	15.97	0.00	1.00000	78	BB	.036	
52	16.36	0.00	1.00000	84	BV	.038	
53	16.45	0.00	1.00000	70	VB	.032	
54	16.75	0.00	1.00000	81	BB	.037	
55	17.11	0.00	1.00000	81	BV	.037	
56	17.19	0.00	1.00000	239	VB	.110	
57	18.59	0.00	1.00000	80	BB	.037	
58	19.12	0.00	1.00000	68	BB	.031	

TOTAL AREA = 218096 TOTAL MASS-% = 100.000
INJECTED AT 11:25:08 ON MAY 11, 1988
ACTUAL RUN TIME: 20.017 MINUTES
MCH:METHYLCYCLOHEXANE; DMCH:DIMETHYLCYCLOHEXANE;
ECH:ETHYLCYCLOHEXANE.

TABLE 4-4

AROMATIC SATURATION

RECYCLE GAS ANALYSIS

PLANT #638, RUN 744, PERIOD 17

COMPONENT	VOLUME PERCENT
HYDROGEN	99.3
PROPANE	0.2
NORMAL BUTANE	0.1
ISO-PENTANE	0.1
NORMAL PENTANE	0.2
HEAVIES	0.2
TOTALS	100.0

TABLE 4-5

AROMATIC SATURATION

DEBUTANIZER OVERHEAD GAS ANALYSIS

PLANT #638, RUN 744, PERIOD 17

COMPONENT	VOLUME PERCENT
HYDROGEN	1.8
ETHANE	0.1
PROPANE	13.8
ISO-BUTANE	3.9
NORMAL BUTANE	51.9
ISO-PENTANE	27.4
NORMAL PENTANE	1.1
TOTALS	100.0

5. FRACTIONATION

The 25 gallons of bulk product from the AH Unibon production run were fractionated in several batches using a 3-inch-diameter Oldershaw laboratory column. Reflux ratio was varied from 5:1 to 10:1. The various cuts were blended to produce the candidate endothermic fuels.

The predominant compounds of interest in the bulk AH product are cyclohexane, methylcyclohexane, and dimethylcyclohexane. The fractionation column was adjusted to provide samples with the following fuel candidates:

Fuel Candidate 1   Cyclohexane - End Point

This fuel, which will represent the low cost option, was prepared by simply removing the light hydrocarbons boiling below 72°C.

Fuel Candidate 2   Cyclohexane - Methylcyclohexane

This fraction was prepared to include cyclohexane and methylcyclohexane and all components that boil with or between these components. Cut temperatures of 72°C and 101°C were specified.

Fuel Candidate 3   Cyclohexane - Dimethylcyclohexane

The fraction includes the naphtha cut boiling between cyclohexane and dimethylcyclohexane. The difference between this candidate and fuel

candidate 1 is removal of the heavy ends. Fractionation cuts temperatures of 72°C and 136°C were specified.

Fuel Candidate 4 Methylcyclohexane - Dimethylcyclohexane

This candidate includes the naphtha cut boiling between methylcyclohexane and the dimethylcyclohexanes. The difference between this fraction and fuel candidate 2 is that the cyclohexane was removed from candidate 4.

Fuel Candidate 5 Cyclohexane - End Point; Dimethylcyclohexane Added

This fuel candidate was prepared by spiking a sample of fuel candidate 1 with a mixture of xylenes and then subjecting the mixture to the AH Unibon process to hydrogenate the xylenes to form dimethylcyclohexanes. This was done so that the role of dimethylcyclohexanes in the endothermic fuel reactor could be properly assessed.

The analysis of the five fuel candidates is summarized in Table 5-1. Each of the fuel candidates was found to have the target hydrocarbon distributions. Each fuel candidate was also found to have acceptable freeze point values and smoke point values.

TABLE 5-1

Table I Analysis of Endothermic Fuel Candidates

CANDIDATE NUMBER	1	2	3	4	5
REFERENCE	5880-9	5880-11	5880-13	5880-15	5880-29B
WT. PERCENT*	86.9	64.1	82.4	28.3	
FREEZING POINT, DEG F	>-54	>-54	>-54	>-54	<-55
SMOKE POINT, MM	+50	+50	+50	+50	42
COPPER STRIP CORROSION	1A	1A	1A	1A	1A
CORROSION Ag STRIP	0	0	0	0	0
DENSITY, G/ML	0.7685	0.7693	0.7680	0.7599	0.7726
CARBON, MASS %	84.35	84.65	84.35	85.05	85.1
HYDROGEN, MASS %	13.9	14.3	14.2	14.4	14.6
SULFUR, MASS %	.1	.1	.1	.1	.1
NITROGEN, MASS PPM	>0.1	>0.1	>0.1	>0.1	<0.1
STABILITY OF GASOLINE, MG/100 ML	1.7	0.3	0.1	0.3	3.5
EXISTENT GUM, MG/ML	2.1	0.1	0.4	0.1	
HEAT OF COMBUSTION, LECO BTU/LB NET	18,152	18,395	18,204	18,046	18,918
SIMULATED DISTILLATION (D-3710) TEMPERATURES IN DEGREES C					
PERCENT ELUTED (MASS)					
IBP	57	36	58	87	58
5	76	77	77	97	84
10	85	85	85	99	85
25	86	86	87	104	87
50	88	88	88	106	105
75	105	103	105	119	127
90	125	105	119	127	134
95	135	106	126	133	135
99.5	202	108	138	141	176
COMPONENT ANALYSIS					
N-PENTANE	0.1	0.6	0.1		
CYCLOPENTANE	0.1		0.1		.1
C6-ISOPARAFFINS	0.7	0.4	0.5		
N-HEXANE	1.7	1.4	1.6		1.4
METHYLCYCLOPENTANE	2.5	2.3	2.3		1.7
CYCLOHEXANE	52.7	82.5	53.9	0.3	31.6
C7-ISOPARAFFINS	1.7	2.2	1.8	1.3	1.0
N-HEPTANE	3.3	4.2	3.6	8.3	2.1
C7-CYCLOPENTANES	3.8	4.7	4.1	3.3	2.4
METHYLCYCLOHEXANE	19.6	21.3	21.3	57.9	12.3
C8-ISOPARAFFINS	1.0	0.1	1.1	4.1	.7
N-OCTANE	1.6		1.7	3.5	1.0
C8-CYCLOPENTANES	1.4	0.2	1.5	4.1	.1
C8-CYCLOHEXANES	5.4	0.1	5.5	15.0	40.4
C9 NAPHTHENES	1.8		0.6	1.5	1.3
C9 PARAFFINS	1.0		0.3	0.7	.6
C10 NAPHTHENES	0.5				.1
C10 PARAFFINS	0.3				.4
C11 NAPHTHENES	0.1				.1
C11 PARAFFINS	0.1				.1
C12 NAPHTHENES + PARAFFINS	0.1				
POLYNAPHTHENES	0.4				.3
>200 P+N	0.1				

* Wt percent recovered by fractionation from AH Unibon product

6. ECONOMIC ANALYSIS

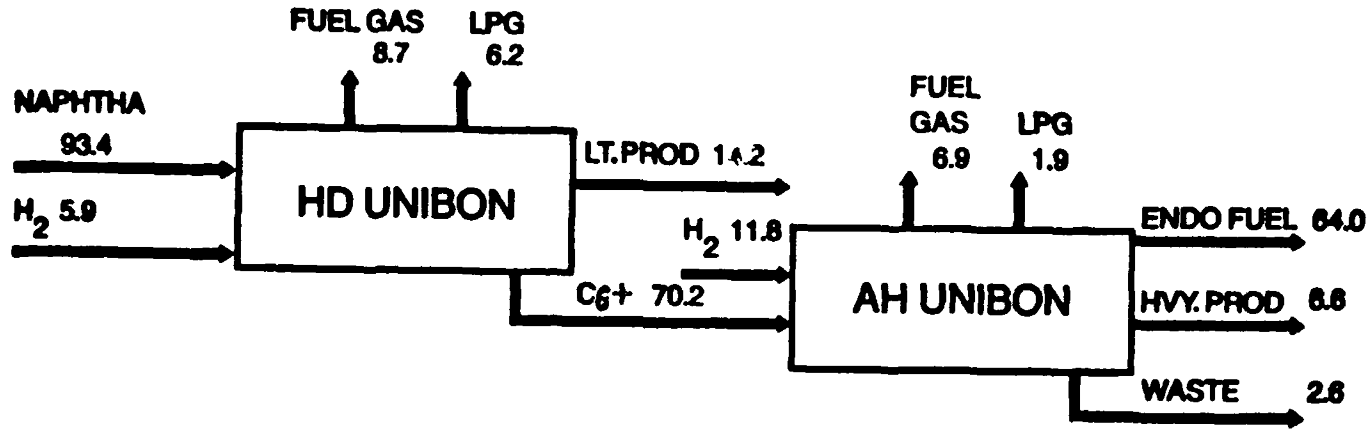
6.1 Endothermic Fuel Production Complex

The endothermic fuel production complex is shown in Figure 6-1. The proposed plant is composed of two process units: UOP HD Unibon (hydrotreating) and UOP AH Unibon (saturation of aromatics). A material balance of the complex is given in Table 6-1.

UOP HD Unibon

The hydrotreating process is essentially that of selective hydrogenation of a hydrocarbon feedstock in the presence of excess hydrogen, over a catalyst at elevated temperature and pressure. The removal of contaminants involves the controlled breaking of the molecular chain or ring at the point where the sulfur, nitrogen, or oxygen atom is joined to a carbon atom. This breaking is accomplished by the introduction of hydrogen with the resultant production of hydrogen sulfide, ammonia, and water, respectively. Hydrotreater process conditions also allow the simultaneous saturation of olefinic compounds in the naphtha charge resulting in a clean feedstock to downstream process units. UOP's practice has been to specify two-stage hydrotreating for thermal and coal-derived liquids due to the presence of diolefinic compounds that tend to polymerize readily when heated.

At the Great Plains Plant, the raw coal naphtha charge stock was derived by flashing off the Rectisol solvent and performing a crude separation into naphtha, crude phenols, and tar oil fractions. The coal naphtha therefore contained a significant amount of Rectisol solvents, which are light compounds, and heavy non-distillables. Ordinarily, for larger petroleum and coal oil



(FLOW RATES IN METRIC TONS PER DAY)

FIGURE 6-1

ENDOTHERMIC FUEL COMPLEX FLOW SCHEME

TABLE 6-1

Endothermic Fuel Plant Material Balance

Total Complex		Flow Rate, MT/D
Feeds	Coal Naphtha	93.4
	Makeup Hydrogen*	17.7
Total		111.1
Products	Flue Gas	15.6
	LPG	8.1
	Light Product	14.2
	Endothermic Fuel	64.0
	Heavy Product	6.6
	Waste	2.6
Total		111.1

* 80 mol % Hydrogen

refineries, an HD Unibon yield estimate would specify stripping and rerunning of the feedstock, supplemented by appropriate inhibitor injection, before the hydrotreating unit. For the hydrotreating of 709 BPD of raw coal naphtha feed from the Great Plains complex, the prefractionation requirement was not included. Instead, the first stage hydrotreating catalyst may need more frequent replacement, due to the absorption of carbonaceous and deleterious material found in the bottom 5% of the feed. The second stage of the hydrotreater employed two reactors, with the second reactor at a lower temperature than the first. This prevents sulfur recombination reactions that are possible with high H_2S concentrations and a light, highly olefinic charge stock.

The yield estimate for UOP two-stage hydrotreating is shown in Table 6-2. Product distribution and C6+ product properties were based on pilot plant results. Note that the naphtha was assumed to be available for processing without a water separation step. Makeup hydrogen was a Platforming® unit offgas or equivalent (~80 mol % hydrogen). The source of hydrogen does not have to be a reformer. At Great Plains, hydrogen derived from synthesis gas by shift reaction and Pressure Swing Absorption (PSA) will have 99.99+% purity and will far exceed quality specified for hydrotreating and aromatics saturation. The use of 99+% purity hydrogen will not affect the results of the economic study. The light end fractions were removed from the hydrotreated product and the heavy fraction, containing the endothermic fuel precursors, was sent to an AH Unibon unit.

<u>UOP AH Unibon</u>

UOP AH Unibon is a catalytic process that treats hydrocarbon feedstocks for aromatic reduction (via saturation of aromatic compounds) without conversion to

TABLE 6-2

Two-Stage HD Unibon Hydrotreater Yields

Feedstock	MT/D
Coal Naphtha	93.4
Makeup Hydrogen*	5.9
	99.3

Product	
Fuel Gas	8.7
LPG	6.2
Light Product	14.2
Hydrotreated Naphtha	70.2
	99.3

Properties	Feedstock	Product(C6+)
API Gravity	39.2	41.2
Distillation, °F**		
IBP	117	-
50%	185	224
EP	350	-
Sulfur, wt %	1.58	0.00005
Total Nitrogen, wt ppm	1980	<1
Paraffins, vol %	-	23
Naphthenes, vol %	-	20
Aromatics, vol %**	50	57
Bromine Number	61.4	<1
Diene Value	9.1	-
Conradson Carbon, wt %**	0.08	<0.005

* 80 mol % Hydrogen

** Estimated

lower boiling compounds by hydrocracking. Operating conditions may be selected to yield a product almost entirely free of aromatics (less than 1 vol %). Virtually all hydrogen consumption is due to the saturation of aromatics.

Hydrotreated C6+ product from the HD Unibon unit is the charge stock to the AH Unibon unit. The charge stock is mixed with recycle liquid, recycle and makeup hydrogen (Platforming unit offgas equivalent, about 80 mol % hydrogen), heated and charged to a series of reactors. Multiple reactors are necessary to control the heat of reaction. The reaction is carried out at low pressure, intermediate space velocity and high hydrogen partial pressure. Reactor effluent is cooled and flows to a separator for recovery of recycle hydrogen. A portion of the separator liquid is recycled back to the reactors to aid in reaction heat removal, while the remaining liquid is stripped for removal of dissolved hydrogen and light ends, which entered the unit with the makeup gas.

The stripped liquid is then fed to a series of fractionation towers to produce the following products:

- an endothermic fuel fraction, largely made up of cycloparaffins, chiefly cyclohexane and methylcyclohexane,

- a heavy product stream containing mostly C8 paraffins and naphthenes, and

- a C9+ waste stream.

Table 6-3 contains the AH Unibon yield estimate which is based primarily on the pilot plant production run results.

TABLE 6-3

AH Unibon Yields

Feedstock	MT/D
Hydrotreated Naphtha	70.2
Makeup Hydrogen*	11.8
Total	82.0
Products	
Fuel Gas	6.9
LPG	1.9
Endothermic Fuel	64.0
Heavy Product (C8's)	6.6
Waste	2.6
Total	82.0
Properties	
AH Unibon Product	
API	51.1
Paraffins, vol %	23
Naphthenes, vol %	77
Aromatics, vol %	<1
Endothermic Fuel Fraction, wt %	~77
Endothermic Fuel	
API	52.5
Sulfur, wt %	0.00005
Total Nitrogen, wt ppm	<1
Cyclohexane + Methylcyclohexane, wt %	85
Freeze Point, °F	<-65

*80 mol % Hydrogen

6.2 Economic Evaluation of Endothermic Fuel Production

This section evaluates the economics of endothermic fuel production. The evaluation determines the price of the endothermic fuel that would be necessary to produce a minimum acceptable rate of return on investment. Product values were calculated for a series of rates of return (5-20%) over a range of feedstock prices (0-300 $/MT). Due to the small scale of the proposed plant (709 BPD fresh feed), a series of sensitivity analyses were completed for different levels of capital investment and annual incomes.

Process Unit Cost Estimates

Erected cost estimates were made for each process unit in the complex. The Inside Battery Limit Estimated Erected Cost (ISBL EEC) includes HD Unibon hydrotreating, AH Unibon and fractionation to final products. No capital cost allocation was made for offsites and utilities. The ISBL EEC was an order of magnitude estimate with an accuracy of +50%. A description of the Estimated Erected Cost basis can be found in Appendix B. Variable costs (utilities and catalyst) and fixed expenses (labor, maintenance, taxes and insurance) were also estimated. A capital and operating cost summary is given in Table 6-4 and does not include costs associated with the operation of offsite facilities. The basis for the utility and labor costs is contained in Table 6-5. The maintenance, taxes, and insurance expenses are calculated as a percentage of EEC.

Price Estimates

Price Estimates for makeup hydrogen and by-products are shown in Table 6-6. Note that the hydrogen cost is for a makeup gas purity of 80% hydrogen. The value listed is equivalent to 900 $/MT for pure hydrogen. The by-product credit prices are reasonable estimates for 1988 second quarter conditions.

TABLE 6-4

Capital and Operating Cost Summary

Process Unit	HD Unibon	AH Unibon
Feed Rate, MT/D	93.4	70.2
EEC, $MM	3.7	5.6
Royalty, $MM	-	0.029
Utility Consumption		
Power, kW	299	167
Condensate, M lb/hr	0.31	0.23
Cooling Water, M gal/hr	0.54	0.48
Fuel, MM Btu/hr	3.00	3.20
Utility Costs, MM/yr	0.15	0.11
Catalyst Loading, lb	4160/4208	2548
Catalyst Loading, $MM	0.011/0.011	0.025
Expected Life, yr	1/5	2
Catalyst Costs, $MM/yr	0.011/0.002	0.013
Catalyst Work Cap., $MM	0.011/0.002	0.186
Labor-Operators/Shift	1	2
Labor Costs, $MM/yr	0.62	1.24
Operating Cost Summary		
Variable Costs		
Utility Costs, $MM/yr	0.150	0.110
Catalyst Costs, $MM/yr	0.014	0.013
Total Variable Costs	0.164	0.123
Fixed Expenses		
Labor Costs, $MM/yr	0.62	1.24
Maintenance, $MM/yr	0.07	0.12
Taxes and Insurance, $MM/yr	0.06	0.08
Total Fixed Expenses	0.75	1.44
Fixed Charges		
EEC Depreciation, $MM/yr	0.37	0.56
Total Fixed Charges	0.37	0.56

TABLE 6-5

Utility and Labor Costs

Power, $/kWh	0.04
Condensate, $/M gal	0.80
Cooling Water, $/M gal	0.10
Fuel, $/MM Btu	2.10
Wage Rate, $/hr	20
Fringe Benefits, %	35
Supervision, %	25
Overhead, %	50

TABLE 6-6

Price and Cost Basis for Economic Analysis

	$/MT
LPG	140
Light Product	130
Heavy Product	144
Waste	122
Fuel Gas	100
Makeup Hydrogen*	232

---

* 80 mol % Hydrogen

Base Case

The estimated costs and expenses, discussed above and summarized in Tables 6-4 through 6-6, define a base case for the economic evaluation. The base case is the best estimate for the cost of building and operating the proposed endothermic fuel plant.

As a preliminary feasibility study, the cost estimates used in defining the base case do not have the accuracy of a detailed design estimate where the results could be used by a general contractor. To determine the impact of the capital and operating costs on the economics of the project, a series of analyses (sensitivity cases) were run using costs that differed from those of the base case. In this manner the project's economic sensitivity to capital costs, to operating costs, and to by-product credits could be determined.

Calculation Method

The economic evaluation calculations were done using a standard discounted cash flow calculation to find an internal rate of return. For each case, a series of internal rate of return calculations were run at assumed naphtha feed costs of 0, 100, 200 and 300 dollars per metric ton. In this manner a series of curves for endothermic fuel value (price in $/MT) versus feed costs were generated for internal rates of return of 5, 10, 15 and 20%. The basis for the economic analysis is summarized in Table 6-7. The calculation method is described in Appendix C.

Results

The results for the internal rate of return calculations for the base case are shown in Table 6-8 as a function of the product value necessary to make a minimum rate of return (IRR). The results are shown graphically in Figure 6-2.

TABLE 6-7

Basis for Economic Analysis

Method:	Discounted Cash Flow/NPV, 100% Equity, Constant $ Basis
Feed Costs:	0, 100, 200, 300 $/MT Where 0 represents WASTE 200 represents current gasoline price (0.52¢/gal)
Discount Rate:	5, 10, 15, 20% Where 5-10% represents T-Bill Rate 20% represents UOP recommended Discount Rate
Depreciation:	Straight line over 10 years
Plant Life:	20 years
Construction Period:	1 year
Tax Rate:	33%

Determine -- Capital Costs, Operating Costs, Product Cost $/MT

TABLE 6-8

Base Case
Endothermic Fuel Value ($/MT) Needed for Minimum Profitability

Feed, $/MT	IRR% 5%	10%	15%	20%
0	133.80	158.30	187.00	218.50
100	279.60	304.00	332.70	364.20
200	425.40	449.90	478.50	510.00
300	571.20	595.70	624.30	655.80

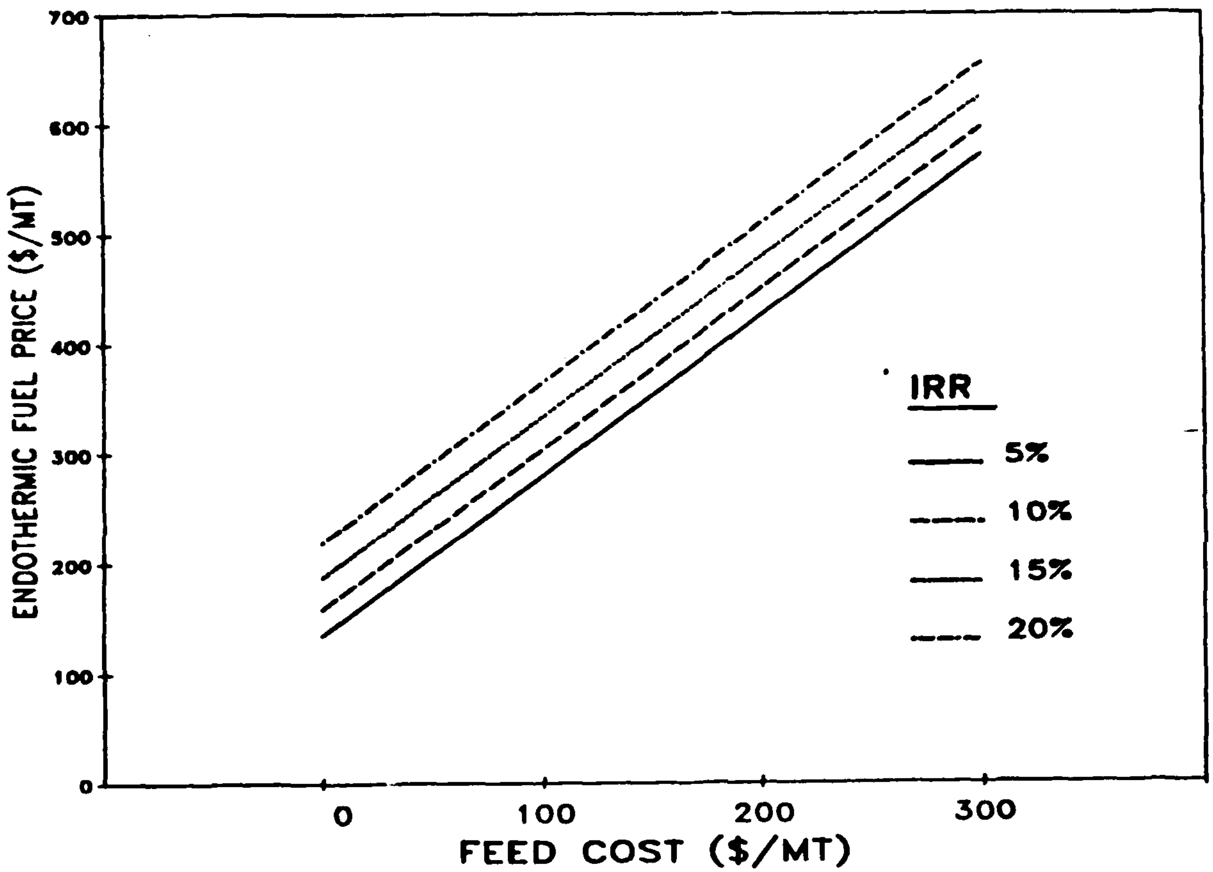


FIGURE 6-2
ENDOTHERMIC FUEL PRODUCTION PLANT
ENDOTHERMIC FUEL VALUE NEEDED FOR MINIMUM PROFITABILITY
BASE CASE

Note that the results are a series of parallel lines with the slope of ~1.46 \$/MT Endothermic Fuel per \$/MT feed cost.

The graph allows the user to obtain a product value necessary to produce a minimum return. For instance, if a feed naphtha costs 140 \$/MT (representative of an average naphtha price, August 1988), what endothermic fuel price is necessary to produce a 15% IRR? Locating the point on the 15% IRR line in Figure 6-2 at a feed price of 140 \$/MT, an endothermic fuel price of ~390 \$/MT is needed to achieve a 15% rate of return. This price of 390 \$/MT is appreciably higher than the current (August 1988) conventional jet fuel price of ~145 \$/MT. The price of 390 \$/MT is reasonably close to the cost of buying toluene in the market and saturating it to produce methylcyclohexane at 309 \$/MT (determined in a study funded by the U.S. Air Force, Contract F33615-86-2633, March 18, 1988). The economics of producing endothermic fuel from coal naphtha are extraordinarily attractive when compared to buying pure methylcyclohexane in the open market (20,000 gallon lots at \$4.73/lb or \$10,430/MT, second quarter 1988).

Sensitivity Analyses

Due to the small size of the endothermic fuel production plant and the inherent limitations of a feasibility study, the cost estimates used in the economic evaluation have a higher than usual degree of uncertainty. A set of sensitivity analyses were run for different levels of capital investment. The capital cost sensitivity cases were:

Sensitivity Case 1: Capital Cost (EEC) +20%

Sensitivity Case 2: Capital Cost (EEC) +40%

Sensitivity Case 3: Capital Cost (EEC) -20%

The evaluation for each case was identical to that of the base case. All data used in the sensitivity analyses 1-3 were the same as for the base case with the exception of the EEC, which was adjusted as shown above. The results for the analyses can be found in Table 6-9 and Figures 6-3 through 6-5.

The results of the sensitivity analyses indicate the impact of capital cost on the profitability of the complex. The greater the capital cost, the greater the price of endothermic fuel required to meet a minimum acceptable rate of return. Looking at the results for the sensitivity case with the largest change in EEC (Sensitivity Case 2: EEC +40%) and using the same example as for the base case, an endothermic product price of 430 $/MT is necessary to produce a 15% rate of return when the feed cost is 140 $/MT. This product price is 10.3% higher than for the base case indicating that the profitability of the complex is not highly sensitive to capital costs. This fact is further borne out when looking at the extreme points of the analyses as shown below:

		Endothermic Fuel Price, $/MT		
Feed Cost, $/MT	%IRR	Base Case	Sens. Case 2	%Increase
0	5	133.8	151.5	13.2
	20	218.5	269.8	23.5
300	5	571.2	588.9	3.1
	20	655.8	707.2	7.8

A second set of sensitivity cases were run to determine the effect of variable costs and by-product credits on the complex profitability. These cases were:

Sensitivity Case 4:	Variable Costs	= Base Case +10%
	By-product Credits	= Base Case -10%
Sensitivity Case 5:	Variable Costs	= Base Case +20%
	By-product Credits	= Base Case -20%
Sensitivity Case 6:	Variable Costs	= Base Case -10%
	By-product Credits	= Base Case +10%

The evaluation for each case was identical to that of the previous cases. The data used in sensitivity analyses 4-6 were the same as for the base case, with the exception of the variable costs and by-product credits that were adjusted, as shown above. The results for the analyses can be found in Table 6-10 and Figures 6-6 through 6-8.

Looking at the results for the sensitivity case with the greatest change in costs and credits (Sensitivity Case 5, +20%) and using the same example as for the base case, an endothermic fuel price of 403 $/MT is necessary to produce a 15% rate of return when the feed cost is 140 $/MT. This product price is only 3.4% higher than for the base case indicating that the profitability of the complex is not highly sensitive to the variable costs and by-product credits. This low sensitivity is also illustrated when looking at the extreme points of the analyses:

		Endothermic Fuel Price, $/MT		
Feed Cost, $/MT	%IRR	Base Case	Sens. Case 2	%Increase
0	5	133.8	146.2	9.3
	20	218.5	230.8	5.6
300	5	571.2	583.6	2.2
	20	655.8	668.2	1.9

TABLE 6-9

Capital Cost (EEC) Sensitivity

Endothermic Fuel Value ($/MT) Needed for Minimum Profitability

Capital Cost = Base Case +20%

Feed, $/MT	IRR% 5%	10%	15%	20%
0	142.60	172.10	206.40	244.10
100	288.40	317.90	352.20	389.90
200	434.20	463.70	498.00	535.70
300	580.00	609.50	643.80	681.50

Capital Cost = Base Case +40%

Feed, $/MT	IRR% 5%	10%	15%	20%
0	151.50	185.70	225.80	269.80
100	297.30	331.50	371.60	415.60
200	443.10	477.30	517.40	561.40
300	588.90	623.10	663.20	707.20

Capital Cost = Base Case -20%

Feed, $/MT	IRR% 5%	10%	15%	20%
0	125.00	144.60	167.60	192.80
100	270.80	290.40	313.40	338.60
200	416.60	436.20	459.10	484.40
300	562.40	582.00	604.90	630.10

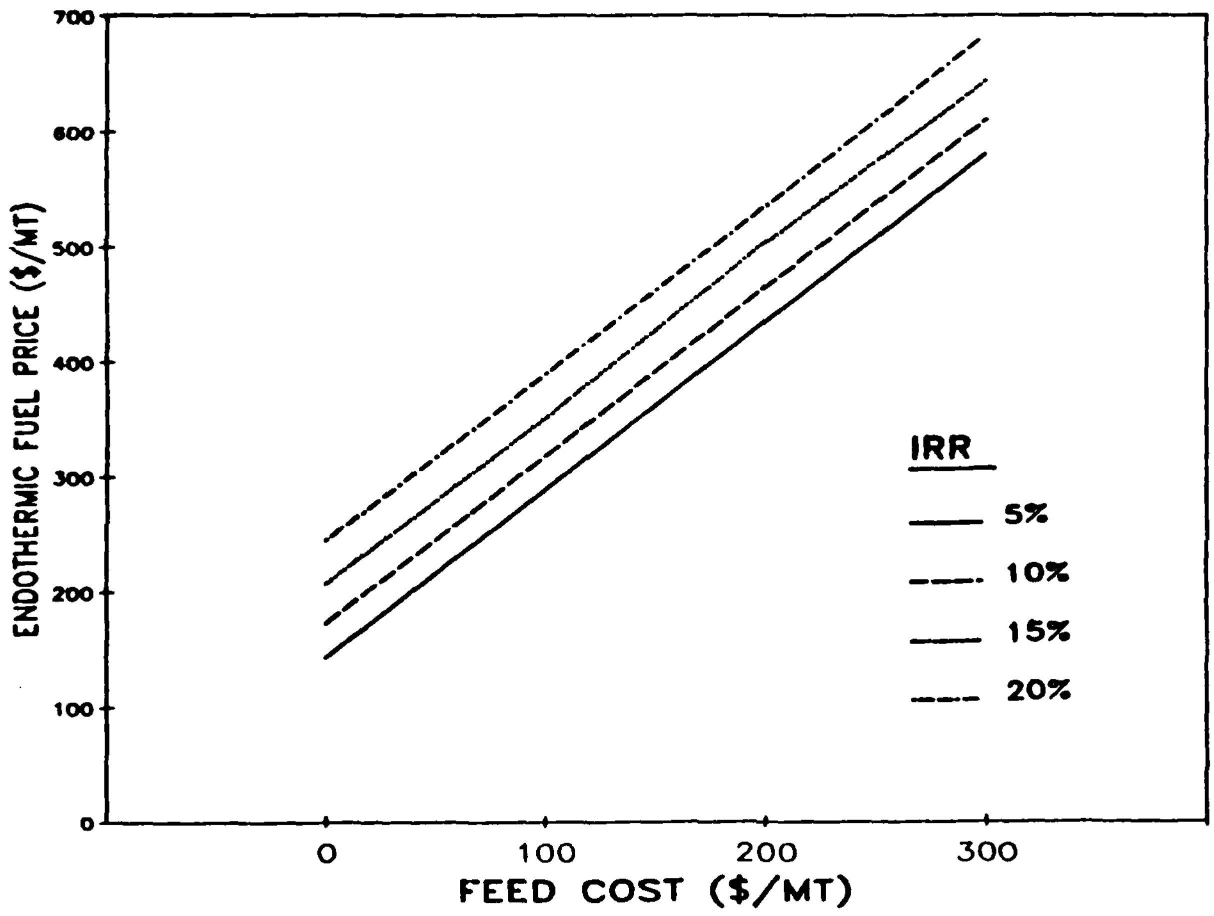


FIGURE 6-3

ENDOTHERMIC FUEL VALUE NEEDED FOR MINIMUM PROFITABILITY SENSITIVITY CASE 1: CAPITAL COST (EEC) +20x

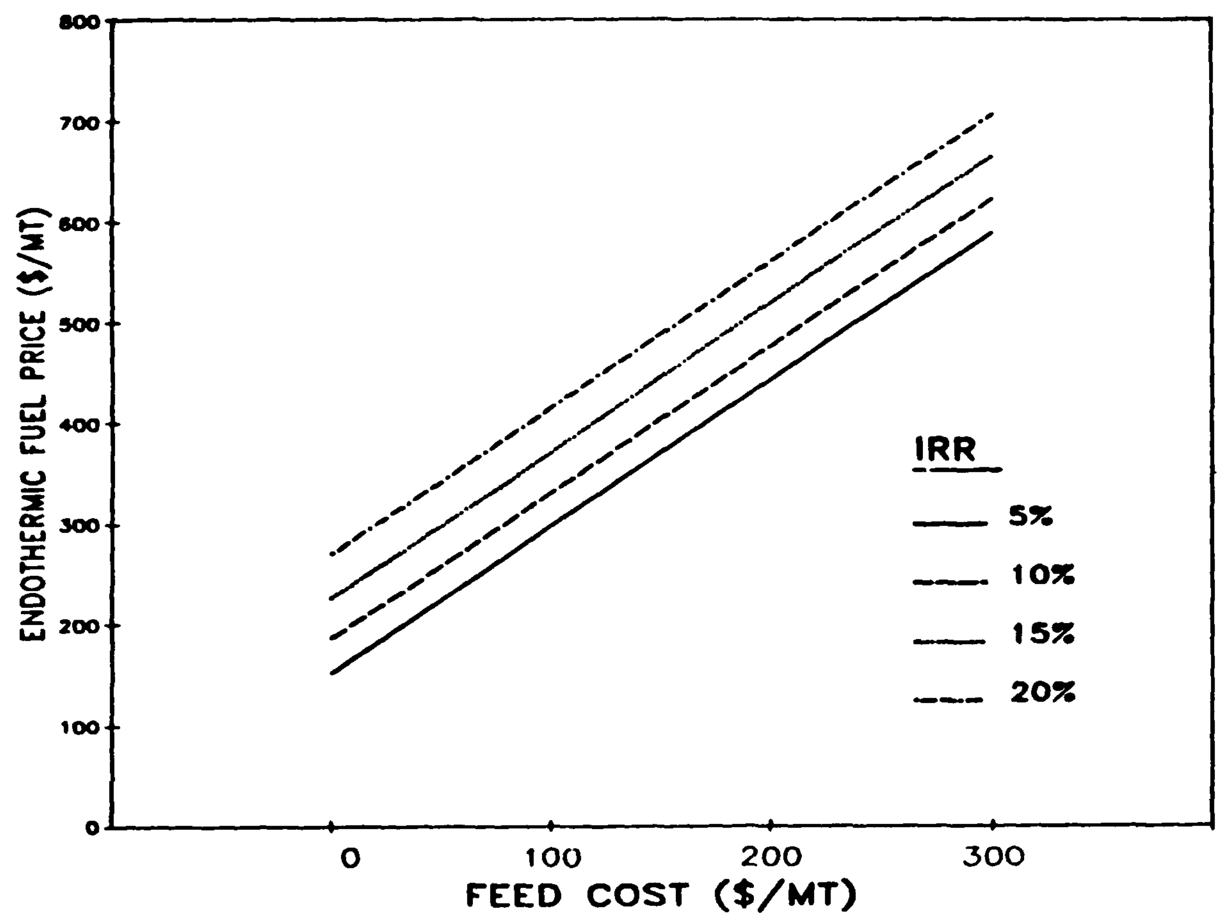


FIGURE 6-4

ENDOTHERMIC FUEL VALUE NEEDED FOR MINIMUM PROFITABILITY SENSITIVITY CASE 2: CAPITAL COST (EEC) +40%

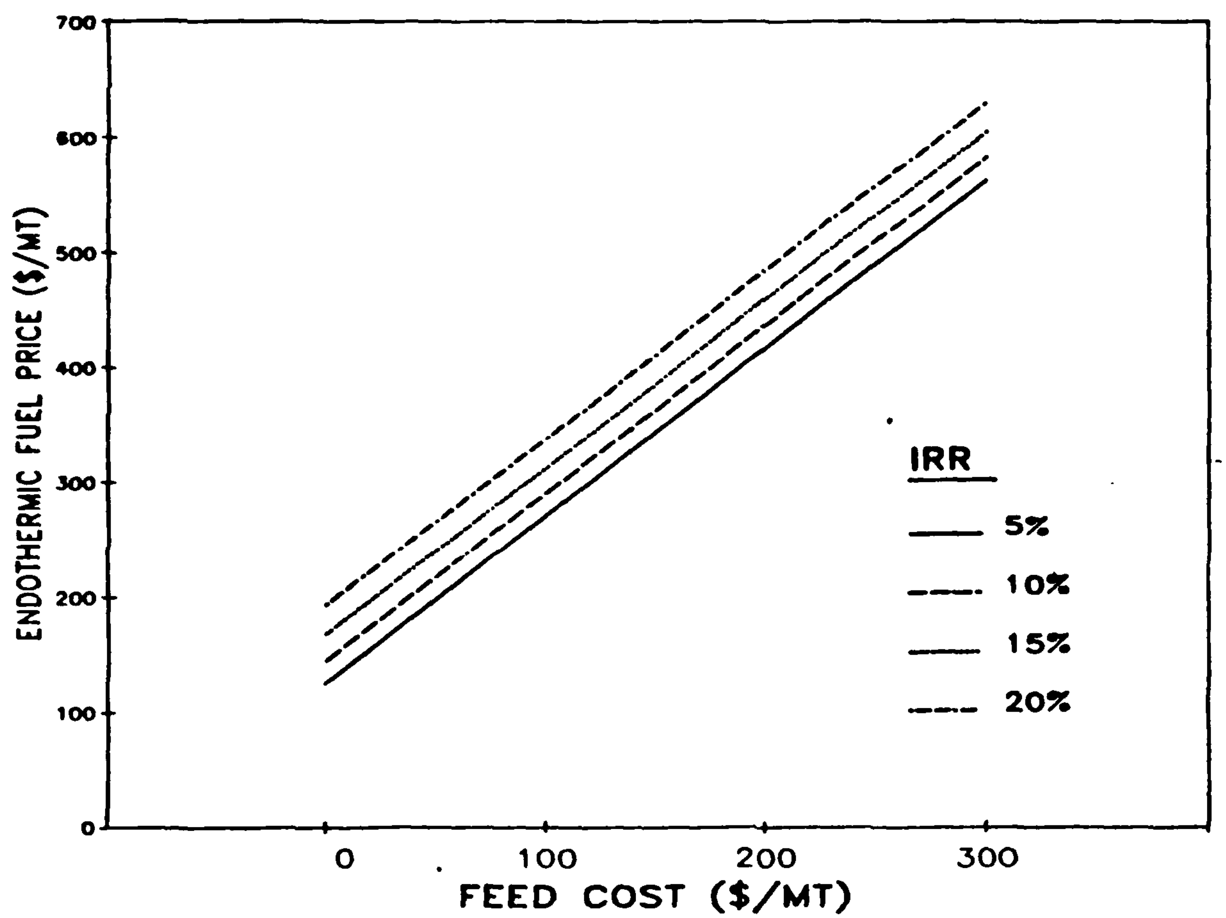


FIGURE 6-5

ENDOTHERMIC FUEL VALUE NEEDED FOR MINIMUM PROFITABILITY SENSITIVITY CASE 3: CAPITAL COST (EEC) -20%

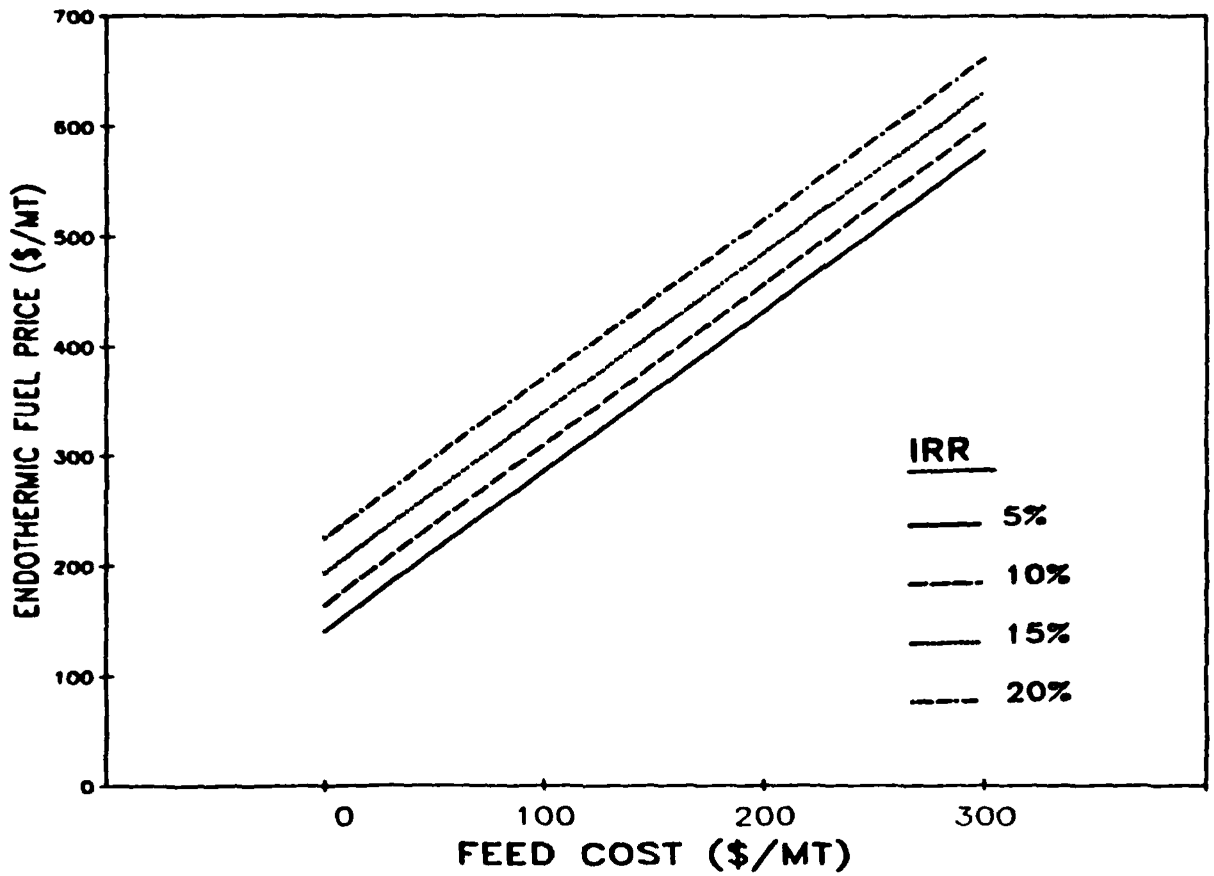


FIGURE 6-6

ENDOTHERMIC FUEL VALUE NEEDED FOR MINIMUM PROFITABILITY
SENSITIVITY CASE 4: VARIABLE COST +10%
BY-PRODUCT CREDITS -10%

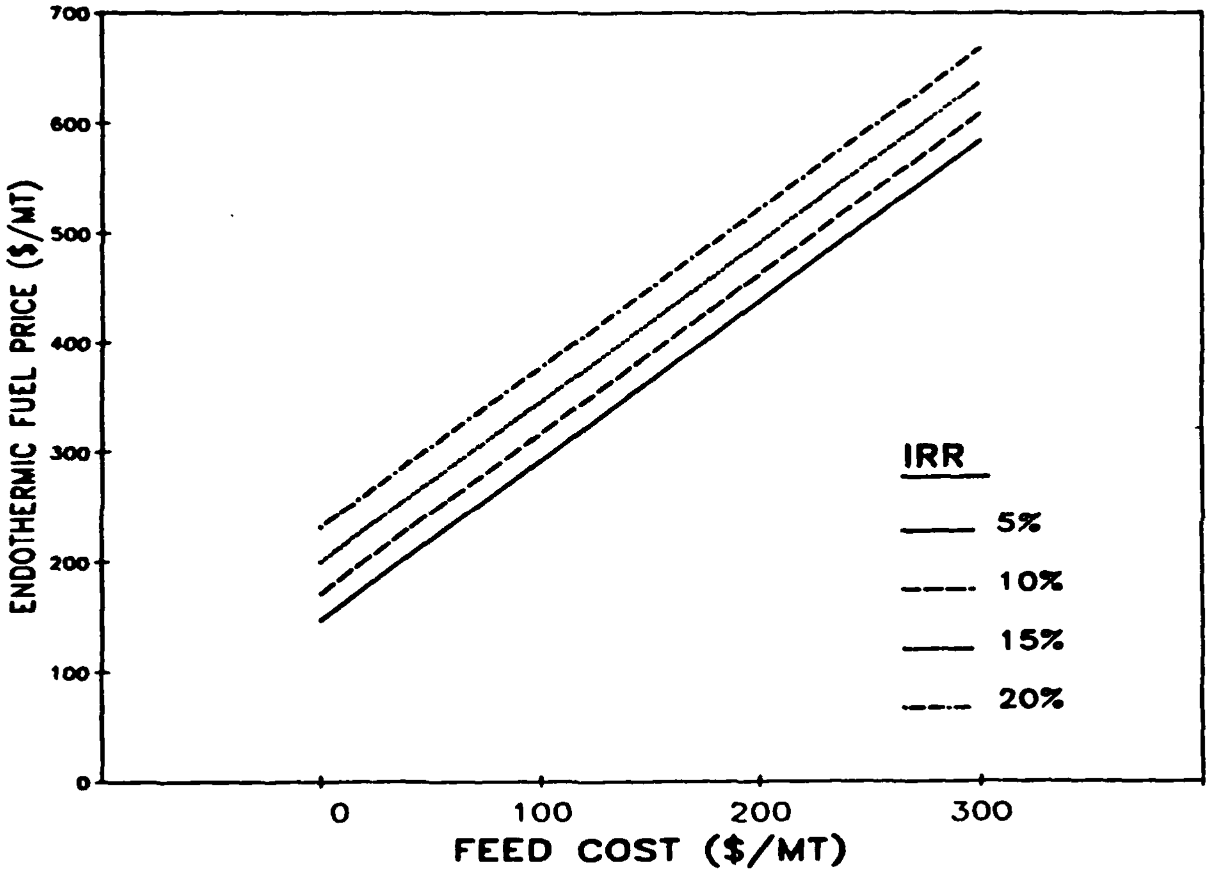


FIGURE 6-7

ENDOTHERMIC FUEL VALUE NEEDED FOR MINIMUM PROFITABILITY
SENSITIVITY CASE 5: VARIABLE COST +20%
BY-PRODUCT CREDITS -20%

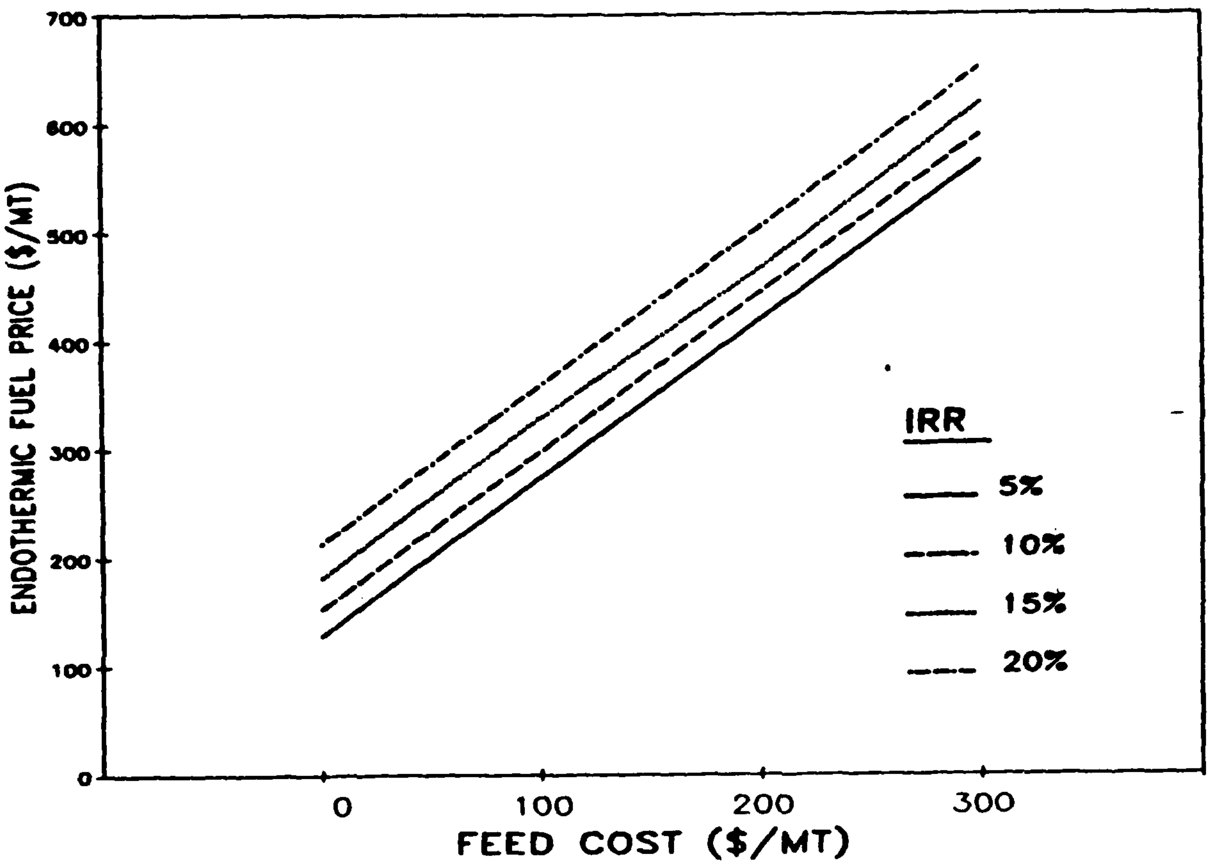


FIGURE 6-8

ENDOTHERMIC FUEL VALUE NEEDED FOR MINIMUM PROFITABILITY
SENSITIVITY CASE 6: VARIABLE COST -10%
BY-PRODUCT CREDITS +10%

TABLE 6-10

Gross Margin (Variable Cost & By-Product Credit) Sensitivity
Endothermic Fuel Value ($/MT) Needed for Minimum Profitability

Variable Costs = Base Case +10%
By-Product Credits = Base Case -10%

Feed, $/MT	IRR% 5%	10%	15%	20%
0	140.00	164.50	193.20	224.60
100	285.80	310.30	339.00	370.40
200	431.60	456.10	484.80	516.20
300	577.40	601.90	630.50	662.00

Variable Costs = Base Case +20%
By-Product Credits = Base Case -20%

Feed, $/MT	IRR% 5%	10%	15%	20%
0	146.20	170.70	199.40	230.80
100	292.00	316.50	345.10	376.60
200	437.80	462.30	490.90	522.40
300	583.60	608.10	636.70	668.20

Variable Costs = Base Case -10%
By-Product Credits = Base Case +10%

Feed, $/MT	IRR% 5%	10%	15%	20%
0	127.60	152.20	180.80	212.30
100	273.40	298.00	326.60	358.00
200	419.20	443.70	472.40	503.80
300	565.00	589.50	618.20	649.60

6.3 Conclusions of Economic Study

(1) At 140 $/MT cost of coal naphtha, 15% IRR, the cost of producing a potential endothermic fuel candidate is 390 $/MT. The analysis includes credits for by-products produced. The coal-derived napntha used for this study has been assigned a fuel oil value. However, it should be noted that the high sulfur content of the naphtha may make it unsuitable for direct use as fuel oil without refining to remove the sulfur. This would reduce the value of the naphtha as a fuel and enhance the economics for the production of endothermic fuel. For example, reducing the fuel value from 140 $/MT to 100 $/MT would decrease the estimated cost of the endothermic fuel at 15% IRR from 390 $/MT to about 330 $/MT.

(2) The economics of producing endothermic fuel from coal naphtha compares reasonably to the cost of producing methylcyclohexane by saturation of toluene (309 $/MT).

(3) The economics of producing endothermic fuel from coal naphtha is highly attractive compared to the cost of buying pure methylcyclohexane in 20,000 gallon lots at $10,430/MT.

(4) The cost of producing endothermic fuel is very sensitive to the cost of the feedstock. Each $/MT increase in feedstock cost yields an increase of 1.46 $/MT in endothermic fuel cost.

(5) The cost of producing endothermic fuel is relatively insensitive to the capital investment (EEC).

(6) The cost of producing endothermic fuel is insensitive to variable costs (utilities and catalyst) and by-product credits.

(7) The price of hydrogen is a major cost of endothermic fuel production. At 140 $/MT cost of coal naphtha, hydrogen cost represents 16.7% of the combined feedstock costs, variable costs and fixed expenses, not including capital.

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7. CONCLUSIONS

The raw naphtha by-product stream from the Great Plains Gasification Plant in Beulah, North Dakota can be converted into a endothermic fuel candidate fuels by:

1. Two-stage hydroprocessing to remove compounds containing sulfur, nitrogen, oxygen and double bonds.

2. Catalytic saturation of the aromatic compounds in the hydrotreated naphtha.

3. Fractionation to obtain the desired boiling point range for application to endothermic fuel systems.

An economic analysis shows that at 140 \$/MT cost of coal naphtha, 15% IRR, the cost of producing a potential endothermic fuel candidate is 390 \$/MT. The analysis includes credits for by-products produced. The coal-derived naphtha used for this study has been assigned a fuel oil value. However, it should be noted that the high sulfur content of the naphtha may make it unsuitable for direct use as fuel oil without refining to remove the sulfur. This would reduce the value of the naphtha as a fuel and enhance the economics for the production of endothermic fuel. For example, reducing the fuel value from 140 \$/MT to 100 \$/MT would decrease the estimated cost of the endothermic fuel at 15% IRR from 390 \$/MT to about 330 \$/MT.

APPENDIX A

Pilot Plant Production Runs

Plant 536 Run 823 2-Stage Hydrotreating

Feedstock #5591-63A Coal Naphtha

Target Conditions	For Reactor 1	For Reactor 2
Pressure, psig	1000	1000
Recycle H_2 Rate, SCFB	7500	7500
Vent Gas Rate, CFH	1	

	Shakedown							
Period Number			1		23		4	
Ending Hours on Stream	20		28		36		52	
Charge, grams	1488		1488		1488		1488	
Charge Rate, cc/hr	226		226		226		226	
Cum. Feed @ Period End, grams	3720		5208		6696		9672	
Control Pressure, psig	1000		1000		1000		1000	
Make-Up H_2 Consumption, SCFB	613.4		584.2		631.6		646.2	
Recycle Gas Rate, SCFB	8440		8440		8440		8440	
Reactor Number	1	2	1	2	1	2	1	2
Average Bed Temperature, Deg C	279	375	279	375	280	386	279	386
Average Block Temperature, Deg C	257	372	258	372	258	372	259	381
Inlet Bed Temperature, Deg C	250	368	251	366	252	366	252	377
Peak Bed Temperature, Deg C	302	377	299	378	297	379	293	392
Peak Bed Temp Location, In	4	2	4	2	4	2	4	2
Outlet Bed Temperature, Deg C	262	375	263	375	265	376	267	384
Delta Bed Temperature, Deg C	51	9	48	12	45	13	41	15
Liquid Product, grams	1371		1325		1378		1383	
Liquid Weight Recovery, wt%	92.1		89.0		92.6		92.9	

APPENDIX A (continued)

Plant 536   Run 823   2-Stage Hydrotreating

Feedstock #5591-63A   Coal Naphtha

Target Conditions	For Reactor 1	For Reactor 2
Pressure, psig	1000	1000
Recycle H_2 Rate, SCFB	7500	7500
Vent Gas Rate, CFH	1	

Period Number	5	6	7	8
Ending Hours on Stream	60	68	84	92
Ending Catalyst Life, BPP	.7	.8	.9	1.0
Charge, grams	1488	1488	1488	1488
Charge Rate, cc/hr	226	226	226	226
Cum. Feed @ Period End, grams	11160	12648	15624	17112
Control Pressure, psig	1000	1000	1000	1000
Make-Up H_2 Consumption, SCFB	638.9	606.1	606.1	598.8
Recycle Gas Rate, SCFB	8115	8440	8440	8440

Reactor Number	1	2	1	2	1	2	1	2
Average Bed Temperature, Deg C	277	386	279	386	279	365	278	365
Average Block Temperature, Deg C	259	381	259	381	259	361	259	361
Inlet Bed Temperature, Deg C	252	376	251	376	253	357	248	355
Peak Bed Temperature, Deg C	294	390	292	391	293	373	291	373
Peak Bed Temp Location, in	4	2	6	2	4	2	5	2
Outlet Bed Temperature, Deg C	267	384	268	385	268	364	269	364
Delta Bed Temperature, Deg C	41	14	41	15	40	16	43	18

Liquid Product, grams	1365	1323	1354	1355
Liquid Weight Recovery, wt%	91.7	88.9	90.9	91.1

APPENDIX A (continued)

Plant 536 Run 823 2-Stage Hydrotreating

Feedstock #5591-63A Coal Naphtha

Target Conditions	For Reactor 1	For Reactor 2
Pressure, psig	1000	1000
Recycle H_2 Rate, SCFB	7500	7500
Vent Gas Rate, CFH	1	

Period Number	9		10		11		12	
Ending Hours on Stream	100		116		124		132	
Ending Catalyst Life, BPP	1.1		1.3		1.4		1.5	
Charge, grams	1488		1488		1488		1488	
Charge Rate, cc/hr	226		226		226		226	
Cum. Feed @ Period End, grams	18600		21576		23064		24552	
Control Pressure, psig	1000		1000		1000		1000	
Make-Up H_2 Consumption, SCFB	620.7		522.1		408.9		503.9	
Recycle Gas Rate, SCFB	8440		8440		8792		8440	
Reactor Number	1	2	1	2	1	2	1	2
Average Bed Temperature, Deg C	278	366	277	377	279	375	278	374
Average Block Temperature, Deg C	259	361	259	371	260	369	261	369
Inlet Bed Temperature, Deg C	253	356	254	366	254	366	254	365
Peak Bed Temperature, Deg C	292	375	291	387	295	384	295	386
Peak Bed Temp Location, In	4	2	5	2	5	2	5	2
Outlet Bed Temperature, Deg C	269	364	268	374	269	372	269	372
Delta Bed Temperature, Deg C	39	19	37	21	41	18	40	20
Liquid Product, grams	1398		1365		1248		1328	
Liquid Weight Recovery, wt%	93.9		91.7		83.9		89.2	

APPENDIX A (continued)

Plant 536 Run 823 2-Stage Hydrotreating

Feedstock #5591-63A Coal Naphtha

Target Conditions	For Reactor 1	For Reactor 2
Pressure, psig	1000	1000
Recycle H_2 Rate, SCFB	7500	7500
Vent Gas Rate, CFH	1	

	Start Production							
Period Number	13		14		15		16	
Ending Hours on Stream	156		180		204		228	
Ending Catalyst Life, BPP	1.8		2.0		2.3		2.6	
Charge, grams	4464		4464		4464		4464	
Charge Rate, cc/hr	226		226		226		226	
Cum. Feed @ Period End, grams	29016		33480		37944		42408	
Control Pressure, psig	1000		1000		1000		1000	
Make-Up H_2 Consumption, SCFB	203.2		199.6		320.1		432.0	
Recycle Gas Rate, SCFB	8440		7748		8456		8480	
Reactor Number	1	2	1	2	1	2	1	2
Average Bed Temperature, Deg C	277	375	281	375	263	372	260	376
Average Block Temperature, Deg C	260	369	263	368	250	362	254	367
Inlet Bed Temperature, Deg C	254	354	257	364	228	360	227	366
Peak Bed Temperature, Deg C	293	388	295	388	273	385	278	394
Peak Bed Temp Location, In	4	2	5	2	14	2	14	2
Outlet Bed Temperature, Deg C	269	372	271	372	272	365	277	371
Delta Bed Temperature, Deg C	39	23	38	23	45	25	51	28
Liquid Product, grams	3976		4053		4132		4128	
Liquid Weight Recovery, wt%	89.1		90.8		92.5		92.5	

APPENDIX A (continued)

Plant 536 Run 823 2-Stage Hydrotreating

Feedstock #5591-63A Coal Naphtha

Target Conditions	For Reactor 1	For Reactor 2
Pressure, psig	1000	1000
Recycle H_2 Rate, SCFB	7500	7500
Vent Gas Rate, CFH	1	

Period Number	17	18	19	20
Ending Hours on Stream	252	276	300	324
Ending Catalyst Life, BPP	2.9	3.1	3.4	3.7
Charge, grams	4464	4464	4464	4464
Charge Rate, cc/hr	226	226	226	226
Cum. Feed @ Period End, grams	46872	51336	55800	60264
Control Pressure, psig	1003	1000	1000	1000
Make-Up H_2 Consumption, SCFB	462.5	491.7	488.0	430.8
Recycle Gas Rate, SCFB	8440	8440	8440	8440

Reactor Number	1	2	1	2	1	2	1	2
Average Bed Temperature, Deg C	250	376	260	386	259	385	259	385
Average Block Temperature, Deg C	254	368	254	376	254	376	255	376
Inlet Bed Temperature, Deg C	226	364	225	376	226	372	226	372
Peak Bed Temperature, Deg C	278	395	278	411	278	410	277	410
Peak Bed Temp Location, In	14	2	14	2	14	2	14	2
Outlet Bed Temperature, Deg C	276	371	275	380	276	380	275	380
Delta Bed Temperature, Deg C	52	31	53	35	52	38	51	38

Liquid Product, grams	4191	4049	4050	3729
Liquid Weight Recovery, wt%	93.9	90.7	90.7	83.5

APPENDIX A (continued)

Plant 536 Run 823 2-Stage Hydrotreating

Feedstock #5591-63A Coal Naphtha

Target Conditions	For Reactor 1	For Reactor 2
Pressure, psig	1000	1000
Recycle H_2 Rate, SCFB	7500	7500
Vent Gas Rate, CFH	1	

Period Number	21		22		23		24	
Ending Hours on Stream	348		372		396		420	
Ending Catalyst Life, BPP	3.9		4.2		4.5		4.8	
Charge, grams	4464		4464		4464		4464	
Charge Rate, cc/hr	226		226		226		226	
Cum. Feed @ Period End, grams	64728		69192		73656		78120	
Control Pressure, psig	1000		1000		1000		1000	
Make-Up H_2 Consumption, SCFB	461.3		477.1		451.5		463.7	
Recycle Gas Rate, SCFB	8440		8440		8440		8440	
Reactor Number	1	2	1	2	1	2	1	2
Average Bed Temperature, Deg C	259	386	260	386	260	385	259	385
Average Block Temperature, Deg C	255	376	256	376	257	375	257	375
Inlet Bed Temperature, Deg C	225	372	224	373	225	373	225	373
Peak Bed Temperature, Deg C	277	412	277	412	278	409	278	409
Peak Bed Temp Location, In	14	2	14	2	14	2	14	2
Outlet Bed Temperature, Deg C	276	380	277	380	277	379	277	388
Delta Bed Temperature, Deg C	52	39	53	39	53	36	53	35
Liquid Product, grams	-		4069		4017		3997	
Liquid Weight Recovery, wt%	-		91.1		90.0		89.6	

APPENDIX A (continued)

Plant 536 Run 823 2-Stage Hydrotreating

Feedstock #5591-63A Coal Naphtha

Target Conditions	For Reactor 1	For Reactor 2
Pressure, psig	1000	1000
Recycle H_2 Rate, SCFB	7500	7500
Vent Gas Rate, CFH	1	

Period Number	25		26		27		28	
Ending Hours on Stream	444		468		492		516	
Ending Catalyst Life, BPP	5.0		5.3		5.6		5.8	
Charge, grams	4464		4464		4464		4464	
Charge Rate, cc/hr	226		226		226		226	
Cum. Feed @ Period End, grams	82584		87048		91512		95976	
Control Pressure, psig	1000		1000		1000		1000	
Make-Up H_2 Consumption, SCFB	478.3		501.4		496.5		500.2	
Recycle Gas Rate, SCFB	8440		8440		8440		8440	
Reactor Number	1	2	1	2	1	2	1	2
Average Bed Temperature, Deg C	262	388	266	396	265	396	265	395
Average Block Temperature, Deg C	260	378	263	386	263	385	262	385
Inlet Bed Temperature, Deg C	226	377	229	383	228	383	228	384
Peak Bed Temperature, Deg C	281	411	386	414	285	417	284	417
Peak Bed Temp Location, In	14	1	14	2	14	2	14	2
Outlet Bed Temperature, Deg C	279	381	285	390	284	390	284	389
Delta Bed Temperature, Deg C	55	34	157	31	57	33	56	33
Liquid Product, grams	4052		4024		4081		4055	
Liquid Weight Recovery, wt%	90.8		90.1		91.4		90.8	

APPENDIX A (continued)

Plant 536 Run 823 2-Stage Hydrotreating

Feedstock #5591-63A Coal Naphtha

Target Conditions	For Reactor 1	For Reactor 2
Pressure, psig	1000	1000
Recycle H_2 Rate, SCFB	7500	7500
Vent Gas Rate, CFH	1	

Period Number	29	30
Ending Hours on Stream	540	564
Ending Catalyst Life, BPP	6.1	6.4
Charge, grams	4464	4464
Charge Rate, cc/hr	226	226
Cum. Feed @ Period End, grams	100440	10494
Control Pressure, psig	1000	1000
Make-Up H_2 Consumption, SCFB	491.7	457.6
Recycle Gas Rate, SCFB	8440	8440

Reactor Number	1	2	1	2
Average Bed Temperature, Deg C	266	395	263	395
Average Block Temperature, Deg C	263	385	263	385
Inlet Bed Temperature, Deg C	229	384	231	385
Peak Bed Temperature, Deg C	285	416	285	418
Peak Bed Temp Location, In	14	2	14	1
Outlet Bed Temperature, Deg C	283	389	283	389
Delta Bed Temperature, Deg C	56	32	54	33

Liquid Product, grams	4108	2880
Liquid Weight Recovery, wt%	92.0	64.5

APPENDIX A (continued)

Plant 536   Run 823   2-Stage Hydrotreating

Feedstock #5591-63B   Coal Naphtha

Target Conditions	For Reactor 1	For Reactor 2
Pressure, psig	1000	1000
Recycle H_2 Rate, SCFB	7500	7500
Vent Gas Rate, CFH	1	

Period Number	31		32		33		34	
Ending Hours on Stream	588		612		636		660	
Ending Catalyst Life, BPP	6.6		6.9		7.1		7.4	
Charge, grams	4464		4464		4464		4464	
Charge Rate, cc/hr	226		226		226		226	
Cum. Feed @ Period End, grams	108104		112568		117032		121496	
Control Pressure, psig	1000		1000		1000		1000	
Make-Up H_2 Consumption, SCFB	485.6		497.8		494.1		491.7	
Recycle Gas Rate, SCFB	8440		8440		8440		8440	
Reactor Number	1	2	1	2	1	2	1	2
Average Bed Temperature, Deg C	265	395	265	395	266	396	265	396
Average Block Temperature, Deg C	264	385	263	385	263	385	263	385
Inlet Bed Temperature, Deg C	267	385	228	384	228	385	227	386
Peak Bed Temperature, Deg C	287	418	285	417	286	418	286	418
Peak Bed Temp Location, in	14	1	14	2	14	1	14	1
Outlet Bed Temperature, Deg C	286	389	285	389	283	389	284	389
Delta Bed Temperature, Deg C	20	33	57	32	58	33	59	32
Liquid Product, grams	4059		4097		4085		4074	
Liquid Weight Recovery, wt%	90.9		91.8		91.5		91.3	

APPENDIX A (continued)

Plant 536 Run 823 2-Stage Hydrotreating

Feedstock #5591-63B Coal Naphtha

Target Conditions	For Reactor 1	For Reactor 2
Pressure, psig	1000	1000
Recycle H_2 Rate, SCFB	7500	7500
Vent Gas Rate, CFH	1	

Period Number	35		36		37		38	
Ending Hours on Stream	684		708		732		756	
Ending Catalyst Life, BPP	7.7		7.9		8.2		8.5	
Charge, grams	4464		4464		4464		4464	
Charge Rate, cc/hr	226		226		226		226	
Cum. Feed @ Period End, grams	125960		130424		134888		139352	
Control Pressure, psig	1000		1000		1000		1000	
Make-Up H_2 Consumption, SCFB	451.5		485.6		428.4		463.7	
Recycle Gas Rate, SCFB	8440		8116		8440		8440	
Reactor Number	1	2	1	2	1	2	1	2
Average Bed Temperature, Deg C	395	395	394	394	265	395	265	396
Average Block Temperature, Deg C	263	384	263	384	262	385	262	385
Inlet Bed Temperature, Deg C	231	385	231	384	231	387	231	387
Peak Bed Temperature, Deg C	286	416	288	418	287	418	287	419
Peak Bed Temp Location, In	14	1	14	2	14	1	13	1
Outlet Bed Temperature, Deg C	284	388	285	388	285	388	284	388
Delta Bed Temperature, Deg C	55	31	57	34	56	31	56	32
Liquid Product, grams	4110		4028		4088		4073	
Liquid Weight Recovery, wt%	92.1		90.2		91.6		91.2	

APPENDIX A (continued)

Plant 536 Run 823 2-Stage Hydrotreating

Feedstock #5591-63B Coal Naphtha

Target Conditions	For Reactor 1	For Reactor 2
Pressure, psig	1000	1000
Recycle H_2 Rate, SCFB	7500	7500
Vent Gas Rate, CFH	1	

Period Number	39		40		41		42	
Ending Hours on Stream	780		804		828		852	
Ending Catalyst Life, BPP	8.8		9.0		9.3		9.6	
Charge, grams	4464		4464		4464		4464	
Charge Rate, cc/hr	226		226		226		226	
Cum. Feed @ Period End, grams	143816		148280		152744		157208	
Control Pressure, psig	1000		1000		1000		1000	
Make-Up H_2 Consumption, SCFB	444.2		449.1		442.0		452.7	
Recycle Gas Rate, SCFB	58		8440		8440		8440	
Reactor Number	1	2	1	2	1	2	1	2
Average Bed Temperature, Deg C	265	396	263	396	265	395	265	395
Average Block Temperature, Deg C	261	385	262	384	263	383	264	384
Inlet Bed Temperature, Deg C	232	390	391	390	233	389	234	389
Peak Bed Temperature, Deg C	287	419	419	419	290	417	291	417
Peak Bed Temp Location, In	14	1	1	1	14	1	14	1
Outlet Bed Temperature, Deg C	284	387	387	387	289	386	289	387
Delta Bed Temperature, Deg C	55	28	28	29	57	28	57	28
Liquid Product, grams	-		4056		4031		4018	
Liquid Weight Recovery, wt%	-		90.9		90.3		90.0	

APPENDIX A (continued)

Plant 536 Run 823 2-Stage Hydrotreating

Feedstock #5591-63B Coal Naphtha

Target Conditions	For Reactor 1	For Reactor 2
Pressure, psig	1000	1000
Recycle H_2 Rate, SCFB	7500	7500
Vent Gas Rate, CFH	1	

Period Number	43		44		45		46	
Ending Hours on Stream	876		900		924		948	
Ending Catalyst Life, BPP	9.9		10.1		10.4		10.7	
Charge, grams	4464		4464		4464		4464	
Charge Rate, cc/hr	226		226		226		226	
Cum. Feed @ Period End, grams	161672		166136		170600		175064	
Control Pressure, psig	1000		1000		1000		1000	
Make-Up H_2 Consumption, SCFB	436.9		438.1		438.1		435.7	
Recycle Gas Rate, SCFB	8340		8340		8373		8373	
Reactor Number	1	2	1	2	1	2	1	2
Average Bed Temperature, Deg C	266	396	265	396	264	395	265	395
Average Block Temperature, Deg C	263	385	263	384	264	384	264	384
Inlet Bed Temperature, Deg C	234	391	232	392	233	392	233	389
Peak Bed Temperature, Deg C	291	418	291	419	293	418	292	417
Peak Bed Temp Location, In	14	1	14	1	14	1	14	1
Outlet Bed Temperature, Deg C	288	388	288	386	290	387	291	386
Delta Bed Temperature, Deg C	57	27	59	27	60	26	59	28
Liquid Product, grams	4023		4049		4060		3970	
Liquid Weight Recovery, wt%	90.1		90.7		90.9		88.9	

APPENDIX A (continued)

Plant 536 Run 823 2-Stage Hydrotreating

Feedstock #5591-638 Coal Naphtha

Target Conditions	For Reactor 1	For Reactor 2
Pressure, psig	1000	1000
Recycle H_2 Rate, SCFB	7500	7500
Vent Gas Rate, CFH	1	

Period Number	47		48		49		50	
Ending Hours on Stream	972		996		1020		1044	
Ending Catalyst Life, BPP	10.9		11.2		11.5		11.8	
Charge, grams	4464		4464		4464		4464	
Charge Rate, cc/hr	226		226		226		226	
Cum. Feed @ Period End, grams	179528		183992		188456		192920	
Control Pressure, psig	1000		1000		1000		1000	
Make-Up H_2 Consumption, SCFB	4430		382.1		438.1		424.7	
Recycle Gas Rate, SCFB	8275		8275		8275		8275	
Reactor Number	1	2	1	2	1	2	1	2
Average Bed Temperature, Deg C	265	395	266	395	265	395	265	395
Average Block Temperature, Deg C	264	383	265	383	265	383	265	383
Inlet Bed Temperature, Deg C	234	389	234	389	265	383	265	383
Peak Bed Temperature, Deg C	292	417	293	418	293	418	293	417
Peak Bed Temp Location, In	14	1	14	1	14	1	14	1
Outlet Bed Temperature, Deg C	290	386	290	386	291	386	292	386
Delta Bed Temperature, Deg C	58	28	59	29	59	29	60	27
Liquid Product, grams	3984		3965		3997		3992	
Liquid Weight Recovery, wt%	89.2		88.8		89.5		89.4	

APPENDIX A (continued)

Plant 536 Run 823 2-Stage Hydrotreating

Feedstock #5591-63B Coal Naphtha

Target Conditions	For Reactor 1	For Reactor 2
Pressure, psig	1000	1000
Recycle H_2 Rate, SCFB	7500	7500
Vent Gas Rate, CFH	1	

Period Number	51	52
Ending Hours on Stream	1068	1092
Ending Catalyst Life, BPP	12.0	12.3
Charge, grams	4464	4464
Charge Rate, cc/hr	226	226
Cum. Feed @ Period End, grams	197384	201848
Control Pressure, psig	1000	1000
Make-Up H_2 Consumption, SCFB	444.2	399.2
Recycle Gas Rate, SCFB	8275	8275

Reactor Number	1	2	1	2
Average Bed Temperature, Deg C	265	395	266	395
Average Block Temperature, Deg C	265	383	265	383
Inlet Bed Temperature, Deg C	233	389	235	390
Peak Bed Temperature, Deg C	293	419	293	419
Peak Bed Temp Location, In	14	2	14	1
Outlet Bed Temperature, Deg C	292	386	291	385
Delta Bed Temperature, Deg C				

Liquid Product, grams	4068	4067
Liquid Weight Recovery, wt%	91.1	91.1

APPENDIX A (continued)

Production Run

Plant 638 Run 744

Saturation of Coal Naphtha Liquid

Charge Stock: 5740-55

Period #	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Hours at End of Period	12	24	36	48	60	72	84	96	108	120	132	144	156	168
Reactor Pressure	784	777	781	779	781	780	781	781	786	786	787	776	778	790
Hydrogen Consumed (SCF/B)	1653	1167	1158	1163	1190	1128	1106	994	1104	1100	1398	1235	1360	1435
Reactor Temperatures, °C														
Block	100-170	170	178	192	215	218	226	230	228	229	225	227	225	232
Catalyst Inlet	86	102	158	176	192	192.6	206	202	203	202	205	203	210	209
Catalyst Maximum	192	214.1	249	268	281	294	315	322	325	321.5	325	320	315	318
Maximum Position, inches					6	5	5	5	5	5	5	5	7	8
Catalyst Outlet	191	212	245	265	290	259	258	264	261	263	260	260	259	263
Naphtha Charged, GMS	2227	3429	3960	3624	3434	3878	3466	3896	3792	3883	3801	3774	3665	3806
Liquid Product Recovered, GMS		5443	4157	4183	2435	3355	4280	3730	3473	4099	4031	3943	2549	4270

APPENDIX A (continued)

Production Run

Plant 638 Run 744

Saturation of Coal Naphtha Liquid

Charge Stock: 5740-55

Period #	15	16	17	18	19	20	21	22	23	24	25	26	27
Hours at End of Period	180	192	204	216	228	240	252	264	276	288	300	312	324
Reactor Pressure	779	778	781	780	779	783	777	775	770	777	778	782	780
Hydrogen Consumed (SCF/B)	1145	840	1164	941	982	814	814	762	964	774	1527	980	1185
Reactor Temperatures, °C													
Block	236	235	233	229	233	236	237	238	238	237	242	257	252
Catalyst Inlet	206	210	216	204	206	200	201	205	207	204	214	211	216
Catalyst Maximum	317	ERR	337	333	332	321	328	328	333	327	331	337	339
Maximum Position, inches	5	6	5	5	5	5	5	5	5	5	5	5	5
Catalyst Outlet	274	273	264	260	266	268	272	272	273	271	282	292	285
Naphtha Charged, GMS	3706	3751	3756	3856	3833	3896	3801	3924	3824	3856	3710	3987	3806
Liquid Product Recovered, GMS	3673	4190	3567	3529	4004	4839	3565	3836	3594	4062	3305	4018	3572

APPENDIX A (continued)

Production Run

Plant 638 Run 744

Saturation of Coal Naphtha Liquid

Charge Stock: 5740-55

Period #	28	29	30	31	32	33	34	35	36	37	38	39	40
Hours at End of Period	336	348	360	372	384	396	408	420	432	444	456	468	480
Reactor Pressure	782	780	773	773	779	777	778	768	774	785	780	775	782
Hydrogen Consumed (SCF/B)	839	672	1161	995	1021	882	103	101	51	569	582	645	560
Reactor Temperatures, °C													
Block	255	257	259	256	252	246	235	239	238	246	245	247	244
Catalyst Inlet	209	208	207	208	202	200	199	202	205	216	211	210	205
Catalyst Maximum	335	331	322	330	328	304	250	258	260	300	305	312	307
Maximum Position, inches	5	5	5	5	5	5	23.5	23.5	23.5	5	5	5	5
Catalyst Outlet	290	282	294	289	285	276	250	258	258	278	284	280	276
Naphtha Charged, GMS	3915	3869	3751	3710	3701	3674	4509	3842	3747	3874	4318	4999	4949
Liquid Product Recovered, GMS	4016	3717	3865	3660	3940	3520	3964	3540	4017	3655	4291	4970	4945

APPENDIX A (continued)

Saturation of Coal Naphtha

PLANT 638 RUN# 744
ON-LINE G.C. ANALYSIS

PERIOD# / HOS	1	2	3	4	5	6	7	8	9	10
9-------BENZENE	0.483	0.000	0.733	0.813	0.092	0.404	0.000	0.000	0.000	0.000
TOLUENE	0.278	0.000	0.310	0.307	0.000	0.163	0.025	0.024	0.025	0.023
ETHYLBENZENE+UK	0.055	0.000	0.056	0.058	0.046	0.064	0.044	0.042	0.044	0.042
P+M-XYLENE+UK	0.083	0.000	0.075	0.071	0.188	0.243	0.197	0.191	0.197	0.194
O-XYLENE+UK	0.069	0.000	0.061	0.069	0.096	0.035	0.000	0.075	0.081	0.096
10------BENZENE	0.545	0.000	0.692	0.686	0.081	0.043	0.000	0.000	0.000	0.000
TOLUENE	0.286	0.000	0.288	0.234	0.000	0.024	0.024	0.023	0.024	0.025
ETHYLBENZENE+UK	0.058	0.000	0.057	0.054	0.049	0.043	0.041	0.041	0.042	0.042
P+M-XYLENE+UK	0.090	0.000	0.070	0.214	0.191	0.194	0.190	0.192	0.193	0.194
O-XYLENE+UK	0.069	0.000	0.065	0.068	0.075	0.074	0.075	0.075	0.076	0.097
11------BENZENE	0.000	1.038	0.746	0.538	0.097	0.000	0.000	0.000	0.000	0.000
TOLUENE	0.000	0.548	0.314	0.172	0.000	0.024	0.024	0.025	0.025	0.025
ETHYLBENZENE+UK	0.006	0.076	0.060	0.199	0.048	0.044	0.043	0.041	0.043	0.044
P+M-XYLENE+UK	0.000	0.140	0.078	0.057	0.185	0.197	0.194	0.191	0.194	0.198
O-XYLENE+UK	0.000	0.066	0.064	0.067	0.096	0.077	0.077	0.075	0.098	0.101
2-------BENZENE	0.000	0.461	0.807	0.516	0.093	0.000	0.000	0.000	0.000	0.000
TOLUENE	0.000	0.196	0.320	0.177	2.000	0.025	0.024	0.024	0.025	0.025
ETHYLBENZENE+UK	0.000	0.049	0.060	0.051	0.046	0.044	0.043	0.042	0.041	0.043
P+M-XYLENE+UK	0.000	0.056	0.079	0.220	0.188	0.195	0.194	0.192	0.189	0.195
O-XYLENE+UK	0.000	0.051	0.062	0.073	0.073	0.077	0.000	0.075	0.076	0.078
--WT% AVERAGE--										
--------BENZENE	3.504	1.023	0.651	0.705	0.088	0.083	0.006	0.000	0.000	0.000
TOLUENE	1.656	0.525	0.283	0.269	0.182	0.023	0.025	0.024	0.025	0.025
ETHYLBENZENE+UK	0.140	0.070	0.057	0.069	0.074	0.085	0.043	0.042	0.042	0.043
P+M-XYLENE+UK	0.379	0.126	0.096	0.143	0.192	0.169	0.193	0.193	0.860	0.195
O-XYLENE+UK	0.118	0.069	0.060	0.067	0.090	0.091	0.056	0.079	0.082	0.093

PLANT 638 RUN# 744
ON-LINE G.C. ANALYSIS

PERIOD# / HOS	11	12	13	14	15	16	17	18	19	20
9-------BENZENE	0.000	0.000	0.267	0.089	0.053	0.000	0.023	0.000	0.000	0.000
TOLUENE	0.025	0.023	0.082	0.033	0.022	0.024	0.032	0.024	0.025	0.024
ETHYLBENZENE+UK	0.043	0.041	0.042	0.040	0.042	0.041	0.041	0.041	0.043	0.043
P+M-XYLENE+UK	0.196	0.194	0.195	0.191	0.194	0.189	0.188	0.191	0.193	0.194
O-XYLENE+UK	0.098	0.099	0.024	0.086	0.074	0.097	0.094	0.095	0.086	0.087
10------BENZENE	0.000	0.000	0.201	0.073	0.076	0.000	0.041	0.000	0.000	0.000
TOLUENE	0.025	0.024	0.061	0.029	0.028	0.025	0.025	0.024	0.025	0.025
ETHYLBENZENE+UK	0.044	0.042	0.043	0.042	0.042	0.041	0.039	0.041	0.042	0.041
P+M-XYLENE+UK	0.197	0.195	0.196	0.191	0.194	0.189	0.191	0.191	0.189	0.065
O-XYLENE+UK	0.077	0.080	0.025	0.097	0.026	0.086	0.099	0.086	0.096	0.094
11------BENZENE	0.000	0.000	0.217	0.071	0.049	0.000	0.030	0.000	0.000	0.000
TOLUENE	0.025	0.024	0.063	0.027	0.024	0.024	0.023	0.023	0.024	0.024
ETHYLBENZENE+UK	0.043	0.043	0.043	0.042	0.042	0.041	0.041	0.040	0.042	0.042
P+M-XYLENE+UK	0.195	0.195	0.199	0.187	0.191	0.193	0.191	0.062	0.195	0.192
O-XYLENE+UK	0.078	0.096	0.028	0.096	0.023	0.088	0.074	0.093	0.097	0.098
2-------BENZENE	0.000	0.000	0.213	0.060	0.053	0.000	0.037	0.000	0.000	0.000
TOLUENE	0.024	0.025	0.066	0.025	0.021	0.025	0.024	0.027	0.025	0.025
ETHYLBENZENE+UK	0.043	0.042	0.042	0.042	0.042	0.041	0.041	0.040	0.042	0.042
P+M-XYLENE+UK	0.195	0.187	0.192	0.194	0.191	0.193	0.184	0.190	0.192	0.192
O-XYLENE+UK	0.097	0.095	0.024	0.073	0.023	0.097	0.072	0.094	0.098	0.088
--WT% AVERAGE--										
--------BENZENE	0.000	0.000	0.356	0.130	0.061	0.057	0.022	0.012	0.000	0.000
TOLUENE	0.024	0.025	0.111	0.042	0.032	0.033	0.030	0.025	0.025	0.025
ETHYLBENZENE+UK	0.044	0.043	0.046	0.042	0.096	0.042	0.042	0.041	0.042	0.042
P+M-XYLENE+UK	0.185	0.195	0.190	0.193	0.176	0.193	0.170	0.178	0.169	0.181
O-XYLENE+UK	0.086	0.083	0.049	0.046	0.058	0.061	0.084	0.085	0.094	0.093

APPENDIX A (Continued)

Saturation of Coal Naphtha

PLANT 638 RUN# 744
ON-LINE G.C. ANALYSIS

PLANT 638 RUN# 744
ON-LINE G.C. ANALYSIS

PERIOD# NOS	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40
1-------BENZENE	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOLUENE	0.025	0.024	0.025	0.024	0.024	0.025	0.024	0.025	0.024	0.025	0.023	0.025	0.025	0.025	0.025	0.025	0.025	0.027	0.025	0.025
ETHYLBENZENE+UK	0.046	0.042	0.042	0.041	0.041	0.041	0.041	0.041	0.045	0.043	0.042	0.044	0.042	0.043	0.042	0.043	0.047	0.043	0.042	0.042
P+M-XYLENE+UK	0.212	0.185	0.192	0.189	0.189	0.192	0.193	0.188	0.056	0.198	0.195	0.200	0.195	0.194	0.185	0.188	0.194	0.192	0.193	0.193
O-XYLENE+UK	0.023	0.075	6.097	0.074	0.093	0.096	0.096	0.095	0.096	0.077	0.075	0.078	0.097	0.073	0.023	0.023	0.097	0.075	0.096	0.075
2-------BENZENE	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOLUENE	0.025	0.027	0.025	0.024	0.024	0.025	0.024	0.025	0.025	0.024	0.025	0.024	0.025	0.025	0.024	0.025	0.026	0.025	0.024	0.024
ETHYLBENZENE+UK	0.043	0.042	0.043	0.042	0.041	0.042	0.042	0.042	0.046	0.041	0.042	0.043	0.043	0.043	0.041	0.044	0.044	0.043	0.043	0.042
P+M-XYLENE+UK	0.193	0.187	0.192	0.190	0.190	0.195	0.194	0.195	0.058	0.194	0.197	0.199	0.192	0.192	0.184	0.188	0.150	0.195	0.192	0.193
O-XYLENE+UK	0.096	0.095	0.077	0.075	0.076	0.077	0.096	0.097	0.096	0.075	0.096	0.098	0.097	0.072	0.023	0.023	0.079	0.076	0.098	0.075
3-------BENZENE	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOLUENE	0.025	0.025	0.025	0.025	0.024	0.025	0.026	0.024	0.024	0.025	0.024	0.025	0.024	0.023	0.025	0.025	0.026	0.025	0.025	0.025
ETHYLBENZENE+UK	0.043	0.042	0.041	0.042	0.040	0.042	0.042	0.041	0.042	0.042	0.042	0.042	0.040	0.043	0.043	0.044	0.042	0.043	0.041	0.044
P+M-XYLENE+UK	0.192	0.192	0.190	0.190	0.186	0.193	0.189	0.191	0.194	0.194	0.207	0.195	0.186	0.192	0.192	0.189	0.193	0.196	0.190	0.193
O-XYLENE+UK	0.086	0.096	0.076	0.076	0.074	0.076	0.095	0.096	0.096	0.076	0.128	0.078	0.096	0.073	0.026	0.072	0.095	0.076	0.097	0.076
4-------BENZENE	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOLUENE	0.025	0.024	0.024	0.024	0.024	0.024	0.025	0.025	0.024	0.000	0.025	0.024	0.024	0.025	0.025	0.025	0.025	0.027	0.025	0.025
ETHYLBENZENE+UK	0.043	0.042	0.045	0.042	0.039	0.043	0.042	0.042	0.046	0.000	0.042	0.041	0.041	0.042	0.044	0.044	0.043	0.043	0.042	0.043
P+M-XYLENE+UK	0.193	0.193	0.193	0.190	0.187	0.194	0.194	0.193	0.857	0.000	0.196	0.196	0.194	0.191	0.191	0.190	0.193	0.194	0.192	0.193
O-XYLENE+UK	0.098	0.096	0.096	0.074	0.093	0.078	0.095	0.095	0.096	0.000	0.076	0.099	0.096	0.072	0.024	0.023	0.076	0.096	0.096	0.076
5-------BENZENE	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.00b	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOLUENE	0.025	0.024	0.024	0.027	0.023	0.024	0.025	0.024	0.025	0.000	0.024	0.024	0.024	0.025	0.025	0.025	0.025	0.025	0.024	0.024
ETHYLBENZENE+UK	0.043	0.042	0.042	0.043	0.043	0.043	0.042	0.042	0.045	0.000	0.042	0.041	0.041	0.042	0.043	0.043	0.043	0.043	0.046	0.043
P+M-XYLENE+UK	0.191	0.192	0.194	0.195	0.195	0.196	0.194	0.193	0.057	0.000	0.196	0.187	0.188	0.189	0.191	0.190	0.194	0.194	0.195	0.190
O-XYLENE+UK	0.097	0.095	0.096	0.075	0.077	0.077	0.097	0.076	0.096	0.000	0.095	0.097	0.096	0.072	0.023	0.023	0.097	0.076	0.095	0.074
6-------BENZENE	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOLUENE	0.025	0.025	0.025	0.024	0.026	0.025	0.023	0.025	0.025	0.000	0.025	0.024	0.025	0.026	0.025	0.024	0.026	0.025	0.025	0.025
ETHYLBENZENE+UK	0.043	0.043	0.043	0.042	0.043	0.042	0.041	0.042	0.047	0.000	0.041	0.041	0.042	0.042	0.042	0.044	0.043	0.045	0.043	0.043
P+M-XYLENE+UK	0.191	0.193	0.194	0.190	0.193	0.190	0.191	0.193	0.069	0.000	0.196	0.192	0.191	0.190	0.189	0.189	0.197	0.058	0.194	0.194
O-XYLENE+UK	0.087	0.077	0.096	0.075	0.075	0.094	0.095	0.077	0.097	0.000	0.100	0.097	0.096	0.024	0.023	0.023	0.077	0.075	0.076	0.079
7-------BENZENE	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOLUENE	0.025	0.025	0.025	0.025	0.024	0.024	0.024	0.025	0.024	0.000	0.024	0.024	0.024	0.024	0.025	0.025	0.026	0.023	0.024	0.025
ETHYLBENZENE+UK	0.042	0.043	0.042	0.041	0.043	0.042	0.043	0.042	0.042	0.000	0.043	0.042	0.042	0.042	0.044	0.043	0.042	0.043	0.042	0.042
P+M-XYLENE+UK	0.191	0.190	0.193	0.185	0.195	0.193	0.193	0.192	0.195	0.000	0.198	0.195	0.192	0.189	0.193	0.190	0.193	0.192	0.193	0.193
O-XYLENE+UK	0.087	0.076	0.077	0.073	0.077	0.095	0.085	0.076	0.096	0.000	0.078	0.097	0.096	0.071	0.024	0.023	0.076	0.075	0.076	0.075
8-------BENZENE	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOLUENE	0.025	0.024	0.025	0.024	0.028	0.024	0.025	0.023	0.025	0.000	0.025	0.024	0.025	0.025	0.025	0.025	0.025	0.024	0.024	0.025
ETHYLBENZENE+UK	0.041	0.042	0.042	0.042	0.043	0.041	0.041	0.043	0.042	0.000	0.042	0.043	0.043	0.043	0.043	0.044	0.043	0.041	0.045	0.043
P+M-XYLENE+UK	0.190	0.193	0.195	0.193	0.196	0.194	0.191	0.194	0.198	0.000	0.197	0.196	0.198	0.188	0.188	0.192	0.193	0.189	0.195	0.194
O-XYLENE+UK	0.095	0.077	0.077	0.075	0.076	0.096	0.096	0.055	0.100	0.000	0.078	0.099	0.090	0.023	0.023	0.024	0.074	0.094	0.095	0.095

APPENDIX A (continued)

Saturation of Coal Naphtha

PLANT 638 RUN# 744
ON-LINE G.C. ANALYSIS

PERIOD#	21	22	23	24	25	26	27	28	29	30
HOS										
9-------BENZENE	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOLUENE	0.024	0.024	0.025	0.025	0.025	0.025	0.025	0.025	0.027	0.000
ETHYLBENZENE+UK	0.042	0.042	0.042	0.042	0.042	0.043	0.042	0.043	0.042	0.000
P+M-XYLENE+UK	0.189	0.189	0.193	0.190	0.193	0.196	0.192	0.195	0.194	0.000
O-XYLENE+UK	0.096	0.096	0.076	0.074	0.097	0.097	0.095	0.077	0.098	0.000
10------BENZENE	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOLUENE	0.025	0.024	0.025	0.025	0.024	0.023	0.025	0.024	0.024	0.025
ETHYLBENZENE+UK	0.042	0.041	0.042	0.042	0.042	0.043	0.042	0.042	0.041	0.042
P+M-XYLENE+UK	0.191	0.187	0.194	0.194	0.194	0.196	0.192	0.196	0.193	0.197
O-XYLENE+UK	0.096	0.075	0.100	0.075	0.067	0.097	0.096	0.077	0.076	0.077
11------BENZENE	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.008
TOLUENE	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.025
ETHYLBENZENE+UK	0.042	0.041	0.042	0.042	0.040	0.040	0.042	0.043	0.042	0.042
P+M-XYLENE+UK	0.188	0.191	0.192	0.192	0.190	0.189	0.192	0.195	0.191	0.194
O-XYLENE+UK	0.096	0.097	0.076	0.076	0.075	0.094	0.095	0.096	0.096	0.096
12------BENZENE	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOLUENE	0.024	0.025	0.024	0.024	0.024	0.024	0.027	0.024	0.024	0.024
ETHYLBENZENE+UK	0.042	0.042	0.042	0.042	0.043	0.041	0.042	0.041	0.042	0.042
P+M-XYLENE+UK	0.190	0.193	0.189	0.191	0.195	0.192	0.194	0.068	0.195	0.194
O-XYLENE+UK	0.095	0.096	0.074	0.076	0.078	0.095	0.096	0.095	0.096	0.077
--WT% AVERAGE--										
--------BENZENE	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOLUENE	0.025	0.025	0.025	0.025	0.025	0.024	0.025	0.025	0.025	0.012
ETHYLBENZENE+UK	0.043	0.042	0.042	0.042	0.042	0.042	0.042	0.042	0.044	0.021
P+M-XYLENE+UK	0.193	0.190	0.193	0.191	0.192	0.193	0.192	0.183	0.138	0.098
O-XYLENE+UK	0.088	0.088	0.085	0.075	0.080	0.089	0.095	0.088	0.095	0.040

PLANT 638 RUN# 744
ON-LINE G.C. ANALYSIS

PERIOD#	31	32	33	34	35	36	37	38	39	40
HOS										
9-------BENZENE	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOLUENE	0.026	0.024	0.025	0.026	0.025	0.025	0.025	0.024	0.023	0.025
ETHYLBENZENE+UK	0.044	0.041	0.042	0.052	0.042	0.044	0.042	0.041	0.043	0.042
P+M-XYLENE+UK	0.198	0.190	0.194	0.200	0.188	0.189	0.192	0.184	0.194	0.194
O-XYLENE+UK	0.090	0.095	0.076	0.026	0.070	0.023	0.075	0.094	0.096	0.095
10------BENZENE	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOLUENE	0.025	0.025	0.026	0.025	0.026	0.026	0.025	0.025	0.025	0.024
ETHYLBENZENE+UK	0.044	0.042	0.043	0.043	0.046	0.044	0.043	0.043	0.043	0.041
P+M-XYLENE+UK	0.198	0.194	0.192	0.189	0.058	0.193	0.192	0.194	0.197	0.190
O-XYLENE+UK	0.078	0.099	0.098	0.025	0.022	0.025	0.075	0.096	0.099	0.095
11------BENZENE	0.000	0.000	0.000	0.000	0.000	0.009	0.000	0.000	0.000	0.000
TOLUENE	0.025	0.025	0.024	0.026	0.024	0.026	0.025	0.025	0.026	0.025
ETHYLBENZENE+UK	0.043	0.041	0.043	0.042	0.044	0.044	0.045	0.042	0.042	0.041
P+M-XYLENE+UK	0.199	0.193	0.191	0.187	0.191	0.191	0.057	0.191	0.193	0.191
O-XYLENE+UK	0.078	0.096	0.097	0.024	0.023	0.023	0.074	0.095	0.075	0.096
12------BENZENE	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOLUENE	0.025	0.024	0.025	0.025	0.025	0.026	0.025	0.025	0.025	0.025
ETHYLBENZENE+UK	0.044	0.042	0.044	0.043	0.042	0.044	0.042	0.041	0.044	0.042
P+M-XYLENE+UK	0.197	0.193	0.195	0.186	0.188	0.197	0.189	0.192	0.193	0.191
O-XYLENE+UK	0.078	0.096	0.074	0.023	0.024	0.103	0.073	0.095	0.075	0.096
--WT% AVERAGE--										
--------BENZENE	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOLUENE	0.025	0.024	0.025	0.025	0.025	0.025	0.025	0.025	0.025	0.025
ETHYLBENZENE+UK	0.043	0.042	0.042	0.043	0.043	0.023	0.023	0.043	0.043	0.042
P+M-XYLENE+UK	0.198	0.194	0.192	0.191	0.178	0.191	0.178	0.181	0.193	0.192
O-XYLENE+UK	0.088	0.094	0.092	0.048	0.027	0.034	0.081	0.085	0.090	0.084

APPENDIX B

ESTIMATED ERECTED COST BASIS

The estimated erected cost basis presented here reflects the current U.S. Gulf Coast battery limits price. It is comprised of a materials and labor (M & L) estimate and design, engineering and contractor's fees, overheads and expenses (DE & CE) allowance. The estimated erected cost given in the report was an order of magnitude type estimate with an accuracy of +50%.

In a preliminary cost estimate, to be used for evaluating competing technologies, it is very common to use Gulf Coast location for determining erected costs. Most process licensors, contractors, and refiners use factors, developed from past experience, to translate these costs to other locations. A more detailed cost and engineering estimate for a specific plant location must consider such economic factors as labor rates, productivity, union or non-union labor, government regulations with regards to equipment procurement, environment, etc. The estimated erected cost of the study was an order of magnitude type estimate with an accuracy of ±0.50%. Hence, the study cost estimates will not be site specific within the continental USA.

The material and labor estimates have been derived by scaling detailed estimates prepared for similar units based upon U.S. Gulf Coast erection to UOP Standards and Specifications. The material and labor estimates are intended to include all direct material and labor, indirect field costs and labor benefits, which are associated with the erection of the battery limits process equipment, including the following specific equipment, categories and services:

Heaters	Compressor Shelter
Vessels and internals	Control house
Heat Exchange equipment	Catalyst handling equipment
Pumps	Sundry construction equipment
Drivers	Temporary field office, warehouse, change house, etc.
Compressors	Field testing
Piping	Expendable Tools
Instruments	Clerical costs associated with construction
Electrical	Final cleaning
Insulation	Miscellaneous field costs
Structural steelwork	Fringe benefits
Fireproofing	
Paving and concrete work	

An allowance for design, engineering and contractor's fees, overheads and expenses, primarily based on past UOP experience, has been added to the total material and labor estimate in order to reach an overall erected cost estimate for the battery limits plant. The figure shown for this DE & CE allowance is for orientation economic purposes only and is intended to cover the following charges:

UOP:	Basic process and engineering design specifications and drawings (Schedule A package), including review of contractor's detailed design of specified equipment items.
Contractor:	Detailed engineering Purchasing, expediting and inspection Construction tools and equipment rental Contractor's field and home office expenses Erection supervision Contractor's fees

Items not included in the estimated UOP investment cost (battery limits) are as follows, unless otherwise specified as included:

- Cost of land, site preparation, and soil investigation.
- Piling or any unusual foundation requirements.
- Docks, marine terminals, or jetties.
- Access roads to site.
- Home office administration building.
- Employees housing, worker's barracks, canteens, recreation facilities, etc.
- Overtime pay during construction.
- Know-how fees and royalties on licensed processes.
- Owner's expenses in developing the project.
- Local permits, taxes and fees, or specific costs of doing business in the area.
- Items concerned with export shipment, such as ocean freight, marine insurance, import taxes, customs, etc.
- Operating capital and investment in goods in progress.
- Escalation on materials and labor due to price fluctuation or economic conditions.
- Contingencies.
- Cost of start-up including testing, manpower, utilities, operating manuals and training programs.
- Spare parts, special tools or maintenance equipment.
- Catalysts, chemicals and raw materials including initial fill.
- Customer or national standards, codes.
- Special pollution or noise control facilities.
- Electrical main substations.
- Power generation.
- Water or hydrocarbon pipelines.
- Additions or extensions to utilities systems or offsites.
- Laboratory supplies.
- Special communications or computer systems.

The following assumptions are normally made regarding economic conditions at the time the job is bid:

- There will be an adequate supply of skilled labor available for construction.
- There will be competitive bidding by contractors.
- The plant will be constructed in the U.S. Gulf Coast.
- There is no lost time due to climatic conditions.
- Material and labor prices are based on the date of the estimate.

APPENDIX C

INTERNAL RATE OF RETURN (IRR) CALCULATION METHOD

(1) Determine the estimated erected cost (EEC) for the complex. The inside-battery-limits costs (ISBL EEC) are shown in the summary tables in Appendix C.

No allowance is made for offsites.

(2) Calculate the total capital. Total capital includes the ISBL EEC, the fully paid license (royalty) and the interest on the capital spent during the construction period. Interest on the capital is charged at the rate of 10% per year. The sum of the interest, royalty, and EEC is the total capital, or investment (INV).

(3) The cash flows are calculated over a 20-year period. Depreciation is calculated using the straight-line method at 10% per year. The income tax rate was assumed to be 33%. Two simplifying assumptions are 100% equity basis (no interest charges in the pre-tax income calculations), and constant dollar basis (no inflation)

P	=	Product Revenue
F	=	Feedstock Cost (or value)
FE	=	Fixed Expenses (labor, maintenance, local taxes and insurance)
VC	=	Variable Costs (utility costs, catalyst costs)
DEP	=	Depreciation (10% of EEC per year)
PTI	=	Pre-tax income
ATI	=	After-tax income
CF(t)	=	Cash flow for year t
PTI	=	P-F-FE-VC-DEP
ATI	=	PTI * (1-0.33)
CF(t)	=	ATI + DEP

The cash flows for years 1-10 will be the same. The cash flows for years 11-20 will be the same but will be different from the first 10 year's cash flows because there is no depreciation.

(4) The discounted cash flow equation to be solved for the internal rate of return (IRR) is:

$$\sum_{T=1}^{20} \frac{CF(T)}{(1+IRR)\wedge t} = INV$$

The calculation method to determine an IRR is straightforward. However, the method to find the correct P to yield the desired return requires an iteration.

a. For a given coal naphtha price and internal rate of return pick an endothermic fuel value.

b. Solve for total product value P

c. Calculate all CF(t)

d. Solve the above equation to find IRR

e. Iterate until the value for endothermic fuel value is found so that the desired IRR is obtained.

(5) For each case calculate product values to obtain IRRs of 5, 10, 15 and 20% at assumed coal naphtha feed costs of 0, 100, 200 and 300 $/MT.

APPENDIX D

COMPLEX ECONOMIC EVALUATION DATA

Endothermic Fuel Production Evaluation Data

ENDOTHERMIC FUELS PRODUCTION -- ECONOMIC EVALUATION
BASE CASE

Capitalization Summary

ISBL EEC	MM	9.30
Royalty	MM	.03
Interest on Capital, 1 yr.	MM	.93
		======
Total Capital	MM	10.26

Basis

Interest Rate 10%
Tax Rate 33%
100% Equity
Constant Dollars

Income Summary

Case 1 Feed = $0/MT	IRR = 5.0%	IRR = 10.0%	IRR = 15.0%	IRR = 20.0%
Gross Margin	$3.42 MM per yr	$3.94 MM per yr	$4.55 MM per yr	$5.22 MM per yr
Variable Costs	$.28 " " "	$.28 " " "	$.28 " " "	$.28 " " "
Fixed Expenses	$2.19 " " "	$2.19 " " "	$2.19 " " "	$2.19 " " "
ISBL Depreciation	$.93 " " "	$.93 " " "	$.93 " " "	$.93 " " "
Total Pretax Income yrs 1-10	$.01 MM per yr	$.54 MM per yr	$1.15 MM per yr	$1.82 MM per yr
Total Aftax Income yrs 1-10	$.01 " " "	$.36 " " "	$.77 " " "	$1.22 " " "
Cash Flow yrs 1-10	$.94 " " "	$1.29 " " "	$1.70 " " "	$2.15 " " "
Total Pretax Income yrs 11-20	$.94 MM per yr	$1.47 MM per yr	$2.08 MM per yr	$2.75 MM per yr
Total Aftax Income yrs 11-20	$.63 " " "	$.98 " " "	$1.39 " " "	$1.84 " " "
Cash Flow yrs 11-20	$.63 " " "	$.98 " " "	$1.39 " " "	$1.84 " " "

Gross Margin Calculations

Case 1 Feed= $0 per MT

			IRR = 5.0%		IRR = 10.0%		IRR = 15.0%		IRR = 20.0%	
	lb/hr	MTA	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr
Feedstock										
Coal Naphtha	8,574	31,113	0	0	0	0	0	0	0	0
M.U. Hydrogen	1,631	5,918	232	1.37	232	1.37	232	1.37	232	1.37
Totals	10,205	37,031		1.37		1.37		1.37		1.37
Products										
Fuel Gas	1,436	5,211	100	.52	100	.52	100	.52	100	.52
LPG	743	2,696	140	.38	140	.38	140	.38	140	.38
Light Product	1,305	4,736	130	.62	130	.62	130	.62	130	.62
Endothermic Fuel	5,881	21,341	133.8	2.86	158.3	3.37	187.0	3.99	218.5	4.66
Heavy Product	605	2,195	144	.32	144	.32	144	.32	144	.32
Waste	235	853	122	.10	122	.10	122	.10	122	.10
Totals	10,205	37,031		4.79		5.31		5.93		6.60
Gross Margin				$3.42 MM/yr		$3.94 MM/yr		$4.55 MM/yr		$5.22 MM/yr

ENDOTHERMIC FUELS PRODUCTION -- ECONOMIC EVALUATION
BASE CASE

Capitalization Summary

ISBL EEC	MM	9.30
Royalty	MM	.03
Interest on Capital, 1 yr.	MM	.93
		======
Total Capital	MM	10.26

Basis

Interest Rate 10%
Tax Rate 33%
100% Equity
Constant Dollars

Income Summary

Case 2: Feed = $100/MT		IRR = 5.0%	IRR = 10.0%	IRR = 15.0%	IRR = 20.0%
Gross Margin		$3.42 MM per yr	$3.94 MM per yr	$4.55 MM per yr	$5.22 MM per yr
Variable Costs		$.28 " " "	$.28 " " "	$.28 " " "	$.28 " " "
Fixed Expenses		$2.19 " " "	$2.19 " " "	$2.19 " " "	$2.19 " " "
ISBL Depreciation		$.93 " " "	$.93 " " "	$.93 " " "	$.93 " " "
Total Pretax Income	yrs 1-10	$.01 MM per yr	$.54 MM per yr	$1.15 MM per yr	$1.82 MM per yr
Total Aftax Income	yrs 1-10	$.01 " " "	$.36 " " "	$.77 " " "	$1.22 " " "
Cash Flow	yrs 1-10	$.94 " " "	$1.29 " " "	$1.70 " " "	$2.15 " " "
Total Pretax Income	yrs 11-20	$.94 MM per yr	$1.47 MM per yr	$2.08 MM per yr	$2.75 MM per yr
Total Aftax Income	yrs 11-20	$.63 " " "	$.98 " " "	$1.39 " " "	$1.84 " " "
Cash Flow	yrs 11-20	$.63 " " "	$.98 " " "	$1.39 " " "	$1.84 " " "

Gross Margin Calculations

Case 2: Feed=$100 per MT

			IRR = 5.0%		IRR = 10.0%		IRR = 15.0%		IRR = 20.0%	
	lb/hr	MTA	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr
Feedstock										
Coal Naphtha	8,574	31,113	100	3.11	100	3.11	100	3.11	100	3.11
N.U. Hydrogen	1,631	5,918	232	1.37	232	1.37	232	1.37	232	1.37
Totals	10,205	37,031		4.48		4.48		4.48		4.48
Products										
Fuel Gas	1,436	5,211	100	.52	100	.52	100	.52	100	.52
LPG	743	2,696	140	.38	140	.38	140	.38	140	.38
Light Product	1,305	4,736	130	.62	130	.62	130	.62	130	.62
Endothermic Fuel	5,881	21,341	279.6	5.97	304.0	6.49	332.7	7.10	364.2	7.77
Heavy Product	605	2,195	144	.32	144	.32	144	.32	144	.32
Waste	235	853	122	.10	122	.10	122	10	122	.10
Totals	10,205	37,031		7.90		8.42		9.03		9.71
Gross Margin				$3.42 MM/yr		$3.94 MM/yr		$4.55 MM/yr		$5.22 MM/yr

ENDOTHERMIC FUELS PRODUCTION -- ECONOMIC EVALUATION
BASE CASE

Capitalization Summary

ISBL EEC	MM	9.30
Royalty	MM	.03
Interest on Capital, 1 yr.	MM	.93
		======
Total Capital	MM	10.26

Basis

Interest Rate 10%
Tax Rate 33%
100% Equity
Constant Dollars

Income Summary

Case 3: Feed = $200/MT	IRR = 5.0%	IRR = 10.0%	IRR = 15.0%	IRR = 20.0%
Gross Margin	$3.42 MM per yr	$3.94 MM per yr	$4.55 MM per yr	$5.22 MM per yr
Variable Costs	$.28 " " "	$.28 " " "	$.28 " " "	$.28 " " "
Fixed Expenses	$2.19 " " "	$2.19 " " "	$2.19 " " "	$2.19 " " "
ISBL Depreciation	$.93 " " "	$.93 " " "	$.93 " " "	$.93 " " "
Total Pretax Income yrs 1-10	$.02 MM per yr	$.54 MM per yr	$1.15 MM per yr	$1.82 MM per yr
Total Aftax Income yrs 1-10	$.01 " " "	$.36 " " "	$.77 " " "	$1.22 " " "
Cash Flow yrs 1-10	$.94 " " "	$1.29 " " "	$1.70 " " "	$2.15 " " "
Total Pretax Income yrs 11-20	$.95 MM per yr	$1.47 MM per yr	$2.08 MM per yr	$2.75 MM per yr
Total Aftax Income yrs 11-20	$.63 " " "	$.98 " " "	$1.39 " " "	$1.84 " " "
Cash Flow yrs 11-20	$.63 " " "	$.98 " " "	$1.39 " " "	$1.84 " " "

Gross Margin Calculations

Case 3. Feed=$200 per MT

			IRR = 5.0%		IRR = 10.0%		IRR = 15.0%		IRR = 20.0%	
	lb/hr	MTA	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr
Feedstock										
Coal Naphtha	8.574	31.113	200	6.22	200	6.22	200	6.22	200	6.22
M.U. Hydrogen	1.631	5.918	232	1.37	232	1.37	232	1.37	232	1.37
Totals	10.205	37.031		7.60		7.60		7.60		7.60
Products										
Fuel Gas	1.436	5.211	100	.52	100	.52	100	.52	100	.52
LPG	743	2.695	140	.38	140	.38	140	.38	140	.38
Light Product	1.305	4.736	130	.62	130	.62	130	.62	130	.62
Endothermic Fuel	5.681	21.341	425.4	9.08	449.8	9.60	478.5	10.21	510.0	10.88
Heavy Product	605	2.195	144	.32	144	.32	144	.32	144	.32
Waste	235	853	122	.10	122	.10	122	.10	122	.10
Totals	10.205	37.031		11.01		11.54		12.15		12.82
Gross Margin				$3.42 MM/yr		$3.94 MM/yr		$4.55 MM/yr		$5.22 MM/yr

ENDOTHERMIC FUELS PRODUCTION -- ECONOMIC EVALUATION
BASE CASE

Capitalization Summary

ISBL EEC	MM	9.30
Royalty	MM	.03
Interest on Capital, 1 yr.	MM	.93
		======
Total Capital	MM	10.26

Basis

Interest Rate 10%
Tax Rate 33%
100% Equity
Constant Dollars

Income Summary

Case 4 Feed = $300/MT	IRR = 5.0%	IRR = 10.0%	IRR = 15.0%	IRR = 20.0%
Gross Margin	$3.42 MM per yr	$3.94 MM per yr	$4.55 MM per yr	$5.22 MM per yr
Variable Costs	$.28 " " "	$.28 " " "	$.28 " " "	$.28 " " "
Fixed Expenses	$2.19 " " "	$2.19 " " "	$2.19 " " "	$2.19 " " "
ISBL Depreciation	$.93 " " "	$.93 " " "	$.93 " " "	$.93 " " "
Total Pretax Income yrs 1-10	$.02 MM per yr	$.54 MM per yr	$1.15 MM per yr	$1.82 MM per yr
Total Aftax Income yrs 1-10	$.01 " " "	$.36 " " "	$.77 " " "	$1.22 " " "
Cash Flow yrs 1-10	$.94 " " "	$1.29 " " "	$1.70 " " "	$2.15 " " "
Total Pretax Income yrs 11-20	$.95 MM per yr	$1.47 MM per yr	$2.08 MM per yr	$2.75 MM per yr
Total Aftax Income yrs 11-20	$.63 " " "	$.98 " " "	$1.39 " " "	$1.84 " " "
Cash Flow yrs 11-20	$.63 " " "	$.98 " " "	$1.39 " " "	$1.84 " " "

Gross Margin Calculations

Case 4 Feed=$300 per MT

			IRR = 5.0%		IRR = 10.0%		IRR = 15.0%		IRR = 20.0%	
	lb/hr	MTA	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr
Feedstock										
Coal Naphtha	8,574	31,113	300	9.33	300	9.33	300	9.33	300	9.33
H.U. Hydrogen	1,631	5,918	232	1.37	232	1.37	232	1.37	232	1.37
Totals	10,205	37,031		10.71		10.71		10.71		10.71
Products										
Fuel Gas	1,436	5,211	100	.52	100	.52	100	.52	100	.52
LPG	743	2,696	140	.38	140	.38	140	.38	140	.38
Light Product	1,305	4,736	130	.62	130	.62	130	.62	130	.62
Endothermic Fuel	5,681	21,341	571.2	12.19	595.7	12.71	624.3	13.32	655.8	14.00
Heavy Product	805	2,195	144	.32	144	.32	144	.32	144	.32
Waste	235	853	122	.10	122	.10	122	.10	122	.10
Totals	10,205	37,031		14.12		14.65		15.26		15.93
Gross Margin				$3.42 MM/yr		$3.94 MM/yr		$4.55 MM/yr		$5.22 MM/yr

ENDOTHERMIC FUELS PRODUCTION -- ECONOMIC EVALUATION
SENSITIVITY CASE 1: CAPITAL COST (EEC) +20%

Capitalization Summary

ISBL EEC	MM	11.16
Royalty	MM	.03
Interest on Capital, 1 yr.	MM	1.12
		======
Total Capital	MM	12.31

Basis

Interest Rate 10%
Tax Rate 33%
100% Equity
Constant Dollars

Income Summary

Case 1: Feed = $0/MT	IRR = 5.0%	IRR = 10.0%	IRR = 15.0%	IRR = 20.0%
Gross Margin	$3.60 MM per yr	$4.23 MM per yr	$4.97 MM per yr	$5.77 MM per yr
Variable Costs	$.28 " " "	$.28 " " "	$.28 " " "	$.28 " " "
Fixed Expenses	$2.19 " " "	$2.19 " " "	$2.19 " " "	$2.19 " " "
ISBL Depreciation	$1.12 " " "	$1.12 " " "	$1.12 " " "	$1.12 " " "
Total Pretax Income yrs 1-10	$.02 MM per yr	$.65 MM per yr	$1.38 MM per yr	$2.18 MM per yr
Total Aftax Income yrs 1-10	$.01 " " "	$.43 " " "	$.92 " " "	$1.46 " " "
Cash Flow yrs 1-10	$1.13 " " "	$1.55 " " "	$2.04 " " "	$2.58 " " "
Total Pretax Income yrs 11-20	$1.13 MM per yr	$1.76 MM per yr	$2.49 MM per yr	$3.30 MM per yr
Total Aftax Income yrs 11-20	$.76 " " "	$1.18 " " "	$1.67 " " "	$2.21 " " "
Cash Flow yrs 11-20	$.76 " " "	$1.18 " " "	$1.67 " " "	$2.21 " " "

Gross Margin Calculations

Case 1. Feed= $0 per MT

			IRR = 5.0%		IRR = 10.0%		IRR = 15.0%		IRR = 20.0%	
	lb/hr	MTA	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr
Feedstock	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
Coal Naphtha	8,574	31,113	0	0	0	0	0	0	0	0
H.U. Hydrogen	1,631	5,918	232	1.37	232	1.37	232	1.37	232	1.37
	=======	=======	=======	=======	=======	=======	=======	=======	=======	=======
Totals	10,205	37,031		1.37		1.37		1.37		1.37
Products										
Fuel Gas	1,436	5,211	100	.52	100	.52	100	.52	100	.52
LPG	743	2,696	140	.38	140	.38	140	.38	140	.38
Light Product	1,305	4,736	130	.62	130	.62	130	.62	130	.62
Endothermic Fuel	5,881	21,341	142.6	3.04	172.1	3.67	206.4	4.40	244.1	5.21
Heavy Product	605	2,195	144	.32	144	.32	144	.32	144	.32
Waste	235	853	122	.10	122	.10	122	.10	122	.10
	=======	=======	=======	=======	=======	=======	=======	=======	=======	=======
Totals	10,205	37,031		4.98		5.61		6.34		7.14
Gross Margin				$3.60 MM/yr		$4.23 MM/yr		$4.97 MM/yr		$5.77 MM/yr

ENDOTHERMIC FUELS PRODUCTION -- ECONOMIC EVALUATION
SENSITIVITY CASE 1: CAPITAL COST (EEC) +20%

Capitalization Summary				Basis
ISBL EEC	MM	11.16		Interest Rate 10%
Royalty	MM	.03		Tax Rate 33%
Interest on Capital, 1 yr.	MM	1.12		100% Equity
		======		Constant Dollars
Total Capital	MM	12.31		

Income Summary

Case 2: Feed = $100/MT	IRR = 5.0%	IRR = 10.0%	IRR = 15.0%	IRR = 20 0%
Gross Margin	$3.60 MM per yr	$4.23 MM per yr	$4.97 MM per yr	$5.77 MM per yr
Variable Costs	$.28 " " "	$.28 " " "	$.28 " " "	$ 28 " " "
Fixed Expenses	$2.19 " " "	$2.19 " " "	$2.19 " " "	$2.19 " " "
ISBL Depreciation	$1 12 " " "	$1.12 " " "	$1.12 " " "	$1.12 " " "
Total Pretax Income yrs 1-10	$ 02 MM per yr	$.85 MM per yr	$1.38 MM per yr	$2.18 MM per yr
Total Aftax Income yrs 1-10	$.01 " " "	$.43 " " "	$.92 " " "	$1.46 " " "
Cash Flow yrs 1-10	$1.13 " " "	$1.55 " " "	$2.04 " " "	$2.58 " " "
Total Pretax Income yrs 11-20	$1.13 MM per yr	$1.76 MM per yr	$2 49 MM per yr	$3.30 MM per yr
Total Aftax Income yrs 11-20	$.76 " " "	$1.18 " " "	$1.67 " " "	$2.21 " " "
Cash Flow yrs 11-20	$.76 " " "	$1.18 " " "	$1.67 " " "	$2.21 " " "

Gross Margin Calculations

Case 2: Feed=$100 per MT

			IRR =	5.0%	IRR =	10.0%	IRR =	15.0%	IRR =	20,0%
	lb/hr	MTA	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr
Feedstock	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
Coal Naphtha	8,574	31,113	100	3.11	100	3.11	100	3.11	100	3.11
H.U. Hydrogen	1,631	5,918	232	1.37	232	1.37	232	1.37	232	1.37
	=======	=======	=======	=======	=======	=======	=======	=======	=======	=======
Totals	10,205	37,031		4.48		4.48		4.48		4.48
Products										
Fuel Gas	1,436	5,211	100	.52	100	.52	100	.52	100	.52
LPG	743	2,696	140	.38	140	.38	140	.38	140	.38
Light Product	1,305	4,736	130	.62	130	.62	130	.62	130	.62
Endothermic Fuel	5,881	21,341	288.4	6.15	317.9	6.78	352.2	7.52	389.9	8.32
Heavy Product	605	2,195	144	.32	144	.32	144	.32	144	.32
Waste	235	853	122	.10	122	.10	122	.10	122	.10
	=======	=======	=======	=======	=======	=======	=======	=======	=======	=======
Totals	10,205	37,031		8.08		8.72		9.45		10.26
Gross Margin				$3.60 MM/yr		$4.23 MM/yr		$4.97 MM/yr		$5.77 MM/yr

ENDOTHERMIC FUELS PRODUCTION -- ECONOMIC EVALUATION
SENSITIVITY CASE 1: CAPITAL COST (EEC) +20%

Capitalization Summary				Basis
ISBL EEC	MM	11.16		Interest Rate 10%
Royalty	MM	.03		Tax Rate 33%
Interest on Capital, 1 yr.	MM	1.12		100% Equity
		======		Constant Dollars
Total Capital	MM	12.31		

Income Summary

Case 3: Feed = $200/MT	IRR = 5.0%	IRR = 10.0%	IRR = 15.0%	IRR = 20.0%
Gross Margin	$3.60 MM per yr	$4.23 MM per yr	$4.97 MM per yr	$5.77 MM per yr
Variable Costs	$.28 " " "	$.28 " " "	$.28 " " "	$.28 " " "
Fixed Expenses	$2.19 " " "	$2.19 " " "	$2.19 " " "	$2.19 " " "
ISBL Depreciation	$1.12 " " "	$1.12 " " "	$1.12 " " "	$1.12 " " "
Total Pretax Income yrs 1-10	$.02 MM per yr	$.65 MM per yr	$1.38 MM per yr	$2.18 MM per yr
Total Aftax Income yrs 1-10	$.01 " " "	$.43 " " "	$.92 " " "	$1.46 " " "
Cash Flow yrs 1-10	$1.13 " " "	$1.55 " " "	$2.04 " " "	$2.58 " " "
Total Pretax Income yrs 11-20	$1.13 MM per yr	$1.76 MM per yr	$2.49 MM per yr	$3.30 MM per yr
Total Aftax Income yrs 11-20	$.76 " " "	$1.18 " " "	$1.67 " " "	$2.21 " " "
Cash Flow yrs 11-20	$.76 " " "	$1.18 " " "	$1.67 " " "	$2.21 " " "

Gross Margin Calculations

Case 3: Feed=$200 per MT

			IRR = 5.0%		IRR = 10.0%		IRR = 15.0%		IRR = 20.0%	
	lb/hr	MTA	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr
Feedstock										
Coal Naphtha	8,574	31,113	200	6.22	200	6.22	200	6.22	200	6.22
H.U. Hydrogen	1,631	5,918	232	1.37	232	1.37	232	1.37	232	1.37
Totals	10,205	37,031		7.60		7.60		7.60		7.60
Products										
Fuel Gas	1,436	5,211	100	.52	100	.52	100	.52	100	.52
LPG	743	2,696	140	.38	140	.38	140	.38	140	.38
Light Product	1,305	4,736	130	.62	130	.62	130	.62	130	.62
Endothermic Fuel	5,881	21,341	434.2	9.27	463.7	9.90	490.0	10.63	535.7	11.43
Heavy Product	605	2,195	144	.32	144	.32	144	.32	144	.32
Waste	235	853	122	.10	122	.10	122	.10	122	.10
Totals	10,205	37,031		11.20		11.83		12.56		13.37
Gross Margin				$3.60 MM/yr		$4.23 MM/yr		$4.97 MM/yr		$5.77 MM/yr

ENDOTHERMIC FUELS PRODUCTION -- ECONOMIC EVALUATION
SENSITIVITY CASE 1: CAPITAL COST (EEC) +20%

Capitalization Summary

ISBL EEC	MM	11.16
Royalty	MM	.03
Interest on Capital, 1 yr.	MM	1.12
		======
Total Capital	MM	12.31

Basis

Interest Rate 10%
Tax Rate 33%
100% Equity
Constant Dollars

Income Summary

Case 4: Feed = $300/MT	IRR = 5.0%	IRR = 10.0%	IRR = 15.0%	IRR = 20.0%
Gross Margin	$3.60 MM per yr	$4.23 MM per yr	$4.97 MM per yr	$5.77 MM per yr
Variable Costs	$.28 " " "	$.28 " " "	$.28 " " "	$.28 " " "
Fixed Expenses	$2.19 " " "	$2.19 " " "	$2.19 " " "	$2.19 " " "
ISBL Depreciation	$1.12 " " "	$1.12 " " "	$1.12 " " "	$1.12 " " "
Total Pretax Income yrs 1-10	$.02 MM per yr	$.65 MM per yr	$1.38 MM per yr	$2.18 MM per yr
Total Aftax Income yrs 1-10	$.01 " " "	$.43 " " "	$.92 " " "	$1.46 " " "
Cash Flow yrs 1-10	$1.13 " " "	$1.55 " " "	$2.04 " " "	$2.58 " " "
Total Pretax Income yrs 11-20	$1.13 MM per yr	$1.76 MM per yr	$2.49 MM per yr	$3.30 MM per yr
Total Aftax Income yrs 11-20	$.76 " " "	$1.18 " " "	$1.67 " " "	$2.21 " " "
Cash Flow yrs 11-20	$.76 " " "	$1.18 " " "	$1.67 " " "	$2.21 " " "

Gross Margin Calculations
Case 4. Feed=$300 per MT

			IRR = 5.0%		IRR = 10.0%		IRR = 15.0%		IRR = 20.0%	
	lb/hr	MTA	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr
Feedstock	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
Coal Naphtha	8,574	31,113	300	9.33	300	9.33	300	9.33	300	9.33
H.U. Hydrogen	1,631	5,918	232	1.37	232	1.37	232	1.37	232	1.37
	=======	=======	=======	=======	=======	=======	=======	=======	=======	=======
Totals	10,205	37,031		10.71		10.71		10.71		10.71
Products										
Fuel Gas	1,436	5,211	100	.52	100	.52	100	.52	100	.52
LPG	743	2,696	140	.38	140	.38	140	.38	140	.38
Light Product	1,305	4,736	130	.62	130	.62	130	.62	130	.62
Endothermic Fuel	5,881	21,341	580.0	12.38	608.5	13.01	643.8	13.74	681.5	14.54
Heavy Product	605	2,195	144	.32	144	.32	144	.32	144	.32
Waste	235	853	122	.10	122	.10	122	.10	122	.10
	=======	=======	=======	=======	=======	=======	=======	=======	=======	=======
Totals	10,205	37,031		14.31		14.94		15.67		16.48
Gross Margin				$3.60 MM/yr		$4.23 MM/yr		$4.97 MM/yr		$5.77 MM/yr

ENDOTHERMIC FUELS PRODUCTION -- ECONOMIC EVALUATION
SENSITIVITY CASE 2: CAPITAL COST (EEC) +40%

Capitalization Summary

ISBL EEC	MM	13.02
Royalty	MM	.03
Interest on Capital, 1 yr.	MM	1.30
		======
Total Capital	MM	14.35

Basis

Interest Rate 10%
Tax Rate 33%
100% Equity
Constant Dollars

Income Summary

Case 1: Feed = $0/MT	IRR = 5.0%	IRR = 10.0%	IRR = 15.0%	IRR = 20.0%
Gross Margin	$3.79 MM per yr	$4.52 MM per yr	$5.38 MM per yr	$6.32 MM per yr
Variable Costs	$.28 " " "	$.28 " " "	$.28 " " "	$.28 " " "
Fixed Expenses	$2.19 " " "	$2.19 " " "	$2.19 " " "	$2.19 " " "
ISBL Depreciation	$1.30 " " "	$1.30 " " "	$1.30 " " "	$1.30 " " "
Total Pretax Income yrs 1-10	$.02 MM per yr	$.75 MM per yr	$1.61 MM per yr	$2.55 MM per yr
Total Aftax Income yrs 1-10	$.01 " " "	$.50 " " "	$1.08 " " "	$1.71 " " "
Cash Flow yrs 1-10	$1.32 " " "	$1.80 " " "	$2.38 " " "	$3.01 " " "
Total Pretax Income yrs 11-20	$1.32 MM per yr	$2.05 MM per yr	$2.91 MM per yr	$3.85 MM per yr
Total Aftax Income yrs 11-20	$.89 " " "	$1.38 " " "	$1.95 " " "	$2.58 " " "
Cash Flow yrs 11-20	$.89 " " "	$1.38 " " "	$1.95 " " "	$2.58 " " "

Gross Margin Calculations
Case 1. Feed= $0 per MT

			IRR = 5.0%		IRR = 10.0%		IRR = 15.0%		IRR = 20.0%	
	lb/hr	MTA	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr
Feedstock	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
Coal Naphtha	8,574	31,113	0	0	0	0	0	0	0	0
M.U Hydrogen	1,631	5,918	232	1.37	232	1.37	232	1.37	232	1.37
	=======	=======	=======	=======	=======	=======	=======	=======	=======	=======
Totals	10,205	37,031		1.37		1.37		1.37		1.37
Products										
Fuel Gas	1,436	5,211	100	.52	100	.52	100	.52	100	.52
LPG	743	2,696	140	.38	140	.38	140	.38	140	.38
Light Product	1,305	4,736	130	.62	130	.62	130	.62	130	.62
Endothermic Fuel	5,881	21,341	151.5	3.23	185.7	3.96	225.8	4.82	269.8	5.76
Heavy Product	605	2,195	144	.32	144	.32	144	.32	144	.32
Waste	235	853	122	.10	122	.10	122	.10	122	.10
	=======	=======	=======	=======	=======	=======	=======	=======	=======	=======
Totals	10,205	37,031		5.17		5.90		6.75		7.68
Gross Margin				$3.79 MM/yr		$4.52 MM/yr		$5.38 MM/yr		$6.32 MM/yr

ENDOTHERMIC FUELS PRODUCTION -- ECONOMIC EVALUATION
SENSITIVITY CASE 2: CAPITAL COST (EEC) +40%

Capitalization Summary

ISBL EEC	MM	13.02
Royalty	MM	.03
Interest on Capital, 1 yr.	MM	1.30
		======
Total Capital	MM	14.35

Basis

Interest Rate 10%
Tax Rate 33%
100% Equity
Constant Dollars

Income Summary

Case 2 · Feed = $100/MT	IRR = 5.0%	IRR = 10.0%	IRR = 15.0%	IRR = 20.0%
Gross Margin	$3.79 MM per yr	$4.52 MM per yr	$5.38 MM per yr	$6.32 MM per yr
Variable Costs	$.28 " " "	$.28 " " "	$.28 " " "	$.28 " " "
Fixed Expenses	$2.19 " " "	$2.19 " " "	$2.19 " " "	$2.19 " " "
ISBL Depreciation	$1.30 " " "	$1.30 " " "	$1.30 " " "	$1.30 " " "
Total Pretax Income yrs 1-10	$.02 MM per yr	$.75 MM per yr	$1.61 MM per yr	$2.55 MM per yr
Total Aftax Income yrs 1-10	$.01 " " "	$.50 " " "	$1.08 " " "	$1.71 " " "
Cash Flow yrs 1-10	$1.32 " " "	$1.80 " " "	$2.38 " " "	$3.01 " " "
Total Pretax Income yrs 11-20	$1.32 MM per yr	$2.05 MM per yr	$2.91 MM per yr	$3.85 MM per yr
Total Aftax Income yrs 11-20	$.89 " " "	$1.38 " " "	$1.95 " " "	$2.58 " " "
Cash Flow yrs 11-20	$.89 " " "	$1.38 " " "	$1.95 " " "	$2.58 " " "

Gross Margin Calculations

Case 2: Feed=$100 per MT

			IRR = 5.0%		IRR = 10.0%		IRR = 15.0%		IRR = 20.0%	
	lb/hr	MTA	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr
Feedstock	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
Coal Naphtha	8,574	31,113	100	3.11	100	3.11	100	3.11	100	3.11
M.U Hydrogen	1,631	5,918	232	1.37	232	1.37	232	1.37	232	1.37
	=======	=======	=======	=======	=======	=======	=======	=======	=======	=======
Totals	10,205	37,031		4.48		4.48		4.48		4.48
Products										
Fuel Gas	1,436	5,211	100	.52	100	.52	100	.52	100	.52
LPG	743	2,696	140	.38	140	.38	140	.38	140	.38
Light Product	1,305	4,736	130	.62	130	.62	130	.62	130	.62
Endothermic Fuel	5,881	21,341	297.3	6.34	331.5	7.07	371.6	7.93	415.6	8.87
Heavy Product	605	2,195	144	.32	144	.32	144	.32	144	.32
Waste	235	853	122	.10	122	.10	122	.10	122	.10
	=======	=======	=======	=======	=======	=======	=======	=======	=======	=======
Totals	10,205	37,031		8.28		9.01		9.86		10.80
Gross Margin				$3.79 MM/yr		$4.52 MM/yr		$5.38 MM/yr		$6.32 MM/yr

ENDOTHERMIC FUELS PRODUCTION -- ECONOMIC EVALUATION
SENSITIVITY CASE 2: CAPITAL COST (EEC) +40%

Capitalization Summary

ISBL EEC	MM	13.02
Royalty	MM	.03
Interest on Capital, 1 yr.	MM	1.30
		======
Total Capital	MM	14.35

Basis

Interest Rate 10%
Tax Rate 33%
100% Equity
Constant Dollars

Income Summary

Case 3: Feed = $200/MT	IRR = 5.0%	IRR = 10.0%	IRR = 15.0%	IRR = 20.0%
Gross Margin	$3.79 MM per yr	$4.52 MM per yr	$5.38 MM per yr	$6.32 MM per yr
Variable Costs	$.28 " " "	$.28 " " "	$.28 " " "	$.28 " " "
Fixed Expenses	$2.19 " " "	$2.19 " " "	$2.19 " " "	$2.19 " " "
ISBL Depreciation	$1.30 " " "	$1.30 " " "	$1.30 " " "	$1.30 " " "
Total Pretax Income yrs 1-10	$.02 MM per yr	$.75 MM per yr	$1.61 MM per yr	$2.55 MM per yr
Total Aftax Income yrs 1-10	$.01 " " "	$.50 " " "	$1.08 " " "	$1.71 " " "
Cash Flow yrs 1-10	$1.32 " " "	$1.80 " " "	$2.38 " " "	$3.01 " " "
Total Pretax Income yrs 11-20	$1.32 MM per yr	$2.05 MM per yr	$2.91 MM per yr	$3.85 MM per yr
Total Aftax Income yrs 11-20	$.89 " " "	$1.38 " " "	$1.95 " " "	$2.58 " " "
Cash Flow yrs 11-20	$.89 " " "	$1.38 " " "	$1.95 " " "	$2.58 " " "

Gross Margin Calculations
Case 3: Feed=$200 per MT

			IRR = 5.0%		IRR = 10.0%		IRR = 15.0%		IRR = 20.0%	
	lb/hr	MTA	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr
Feedstock	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
Coal Naphtha	8,574	31,113	200	6.22	200	6.22	200	6.22	200	6.22
H.U. Hydrogen	1,631	5,918	232	1.37	232	1.37	232	1.37	232	1.37
	=======	=======	=======	=======	=======	=======	=======	=======	=======	=======
Totals	10,205	37,031		7.60		7.60		7.60		7.60
Products										
Fuel Gas	1,436	5,211	100	.52	100	.52	100	.52	100	.52
LPG	743	2,696	140	.38	140	.38	140	.38	140	.38
Light Product	1,305	4,736	130	.62	130	.62	130	.62	130	.62
Endothermic Fuel	5,881	21,341	443.1	9.46	477.3	10.19	517.4	11.04	561.4	11.98
Heavy Product	605	2,195	144	.32	144	.32	144	.32	144	.32
Waste	235	853	122	.10	122	.10	122	.10	122	.10
	=======	=======	=======	=======	=======	=======	=======	=======	=======	=======
Totals	10,205	37,031		11.39		12.12		12.98		13.91
Gross Margin				$3.7947 MM/yr		$4.5246 MM/yr		$5.3803 MM/yr		$6.3193 MM/yr

ENDOTHERMIC FUELS PRODUCTION -- ECONOMIC EVALUATION
SENSITIVITY CASE 2: CAPITAL COST (EEC) +40%

Capitalization Summary

ISBL EEC	MM	13.02
Royalty	MM	.03
Interest on Capital, 1 yr.	MM	1.30
		======
Total Capital	MM	14.35

Basis

Interest Rate 10%
Tax Rate 33%
100% Equity
Constant Dollars

Income Summary

Case 4: Feed = $300/MT	IRR = 5.0%	IRR = 10.0%	IRR = 15.0%	IRR = 20.0%
Gross Margin	$3.79 MM per yr	$4.52 MM per yr	$5.38 MM per yr	$6.32 MM per yr
Variable Costs	$.28 " " "	$.28 " " "	$.28 " " "	$.28 " " "
Fixed Expenses	$2.19 " " "	$2.19 " " "	$2.19 " " "	$2.19 " " "
ISBL Depreciation	$1.30 " " "	$1.30 " " "	$1.30 " " "	$1.30 " " "
Total Pretax Income yrs 1-10	$.02 MM per yr	$.75 MM per yr	$1.61 MM per yr	$2.55 MM per yr
Total Aftax Income yrs 1-10	$.01 " " "	$.50 " " "	$1.08 " " "	$1.71 " " "
Cash Flow yrs 1-10	$1.32 " " "	$1.81 " " "	$2.38 " " "	$3.01 " " "
Total Pretax Income yrs 11-20	$1.32 MM per yr	$2.05 MM per yr	$2.91 MM per yr	$3.85 MM per yr
Total Aftax Income yrs 11-20	$.89 " " "	$1.38 " " "	$1.95 " " "	$2.58 " " "
Cash Flow yrs 11-20	$.89 " " "	$1.38 " " "	$1.95 " " "	$2.58 " " "

Gross Margin Calculations

Case 4: Feed=$300 per MT

			IRR = 5.0%		IRR = 10.0%		IRR = 15.0%		IRR = 20.0%	
	lb/hr	MTA	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr
	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
Feedstock										
Coal Naphtha	8,574	31,113	300	9.33	300	9.33	300	9.33	300	9.33
M.U. Hydrogen	1,631	5,918	232	1.37	232	1.37	232	1.37	232	1.37
	=======	=======	=======	=======	=======	=======	=======	=======	=======	=======
Totals	10,205	37,031		10.71		10.71		10.71		10.71
Products										
Fuel Gas	1,436	5,211	100	.52	100	.52	100	.52	100	.52
LPG	743	2,696	140	.38	140	.38	140	.38	140	.38
Light Product	1,305	4,736	130	.62	130	.62	130	.62	130	.62
Endothermic Fuel	5,881	21,341	589.0	12.57	623.1	13.30	663.2	14.15	707.2	15.09
Heavy Product	605	2,195	144	.32	144	.32	144	.32	144	.32
Waste	235	853	122	.10	122	.10	122	.10	122	.10
	=======	=======	=======	=======	=======	=======	=======	=======	=======	=======
Totals	10,205	37,031		14.50		15.23		16.08		17.03
Gross Margin				$3.79 MM/yr		$4.52 MM/yr		$5.38 MM/yr		$6.32 MM/yr

ENDOTHERMIC FUELS PRODUCTION — ECONOMIC EVALUATION
SENSITIVITY CASE 3: CAPITAL COST (EEC) -20%

Capitalization Summary

ISBL EEC	MM	7.44
Royalty	MM	.03
Interest on Capital, 1 yr.	MM	.75
		======
Total Capital	MM	8.22

Basis

Interest Rate 10%
Tax Rate 33%
100% Equity
Constant Dollars

Income Summary

Case 1: Feed = $0/MT	IRR = 5.0%	IRR = 10.0%	IRR = 15.0%	IRR = 20.0%
Gross Margin	$3.23 MM per yr	$3.65 MM per yr	$4.14 MM per yr	$4.68 MM per yr
Variable Costs	$.28 " " "	$.28 " " "	$.28 " " "	$.28 " " "
Fixed Expenses	$2.19 " " "	$2.19 " " "	$2.19 " " "	$2.19 " " "
ISBL Depreciation	$.74 " " "	$.74 " " "	$.74 " " "	$.74 " " "
Total Pretax Income yrs 1-10	$.01 MM per yr	$.43 MM per yr	$.92 MM per yr	$1.46 MM per yr
Total Aftax Income yrs 1-10	$.01 " " "	$.29 " " "	$.62 " " "	$.98 " " "
Cash Flow yrs 1-10	$.75 " " "	$1.03 " " "	$1.36 " " "	$1.72 " " "
Total Pretax Income yrs 11-20	$.76 MM per yr	$1.18 MM per yr	$1.67 MM per yr	$2.20 MM per yr
Total Aftax Income yrs 11-20	$.51 " " "	$.79 " " "	$1.12 " " "	$1.48 " " "
Cash Flow yrs 11-20	$.51 " " "	$.79 " " "	$1.12 " " "	$1.48 " " "

Gross Margin Calculations
Case 1: Feed= $0 per MT

			IRR = 5.0%		IRR = 10.0%		IRR = 15.0%		IRR = 20.0%	
	lb/hr	MTA	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr
Feedstock										
Coal Naphtha	8,574	31,113	0	0	0	0	0	0	0	0
N.U. Hydrogen	1,631	5,918	232	1.37	232	1.37	232	1.37	232	1.37
Totals	10,205	37,031		1.37		1.37		1.37		1.37
Products										
Fuel Gas	1,436	5,211	100	.52	100	.52	100	.52	100	.52
LPG	743	2,696	140	.38	140	.38	140	.38	140	.38
Light Product	1,305	4,736	130	.62	130	.62	130	.62	130	.62
Endothermic Fuel	5,881	21,341	125.0	2.67	144.6	3.09	167.6	3.58	192.6	4.11
Heavy Product	605	2,195	144	.32	144	.32	144	.32	144	.32
Waste	235	853	122	.10	122	.10	122	.10	122	.10
Totals	10,205	37,031		4.60		5.02		5.51		6.05
Gross Margin				$3.23 MM/yr		$3.65 MM/yr		$4.14 MM/yr		$4.68 MM/yr

ENDOTHERMIC FUELS PRODUCTION -- ECONOMIC EVALUATION
SENSITIVITY CASE 3: CAPITAL COST (EEC) -20%

Capitalization Summary

ISBL EEC	MM	7.44
Royalty	MM	.03
Interest on Capital, 1 yr.	MM	.75
		======
Total Capital	MM	8.22

Basis

Interest Rate 10%
Tax Rate 33%
100% Equity
Constant Dollars

Income Summary

Case 2: Feed = $100/MT	IRR = 5.0%	IRR = 10.0%	IRR = 15.0%	IRR = 20.0%
Gross Margin	$3.23 MM per yr	$3.65 MM per yr	$4.14 MM per yr	$4.68 MM per yr
Variable Costs	$.28 " " "	$.28 " " "	$.28 " " "	$.28 " " "
Fixed Expenses	$2.19 " " "	$2.19 " " "	$2.19 " " "	$2.19 " " "
ISBL Depreciation	$.74 " " "	$.74 " " "	$.74 " " "	$.74 " " "
Total Pretax Income yrs 1-10	$.01 MM per yr	$.43 MM per yr	$.92 MM per yr	$1.46 MM per yr
Total Aftax Income yrs 1-10	$.01 " " "	$.29 " " "	$.62 " " "	$.98 " " "
Cash Flow yrs 1-10	$.75 " " "	$1.03 " " "	$1.36 " " "	$1.72 " " "
Total Pretax Income yrs 11-20	$.76 MM per yr	$1.18 MM per yr	$1.67 MM per yr	[illegible] MM per yr
Total Aftax Income yrs 11-20	$.51 " " "	$.79 " " "	$1.12 " " "	$1.48 " " "
Cash Flow yrs 11-20	$.51 " " "	$.79 " " "	$1.12 " " "	$1.48 " " "

Gross Margin Calculations
Case 2: Feed=$100 per MT

			IRR = 5.0%		IRR = 10.0%		IRR = 15.0%		IRR = 20.0%	
	lb/hr	MTA	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr
Feedstock										
Coal Naphtha	8,574	31,113	100	3.11	100	3.11	100	3.11	100	3.11
M.U Hydrogen	1,631	5,918	232	1.37	232	1.37	232	1.37	232	1.37
Totals	10,205	37,031		4.48		4.48		4.48		4.48
Products										
Fuel Gas	1,436	5,211	100	.52	100	.52	100	.52	100	.52
LPG	743	2,696	140	.38	140	.38	140	.38	140	.38
Light Product	1,305	4,736	130	.62	130	.62	130	.62	130	.62
Endothermic Fuel	5,681	21,341	270.8	5.78	290.4	6.20	313.4	6.68	338.6	7.23
Heavy Product	605	2,195	144	.32	144	.32	144	.32	144	.32
Waste	235	853	122	.10	122	.10	122	.10	122	.10
Totals	10,205	37,031		7.71		8.13		8.62		9.16
Gross Margin				$3.23 MM/yr		$3.65 MM/yr		$4.14 MM/yr		$4.68 MM/yr

ENDOTHERMIC FUELS PRODUCTION -- ECONOMIC EVALUATION
SENSITIVITY CASE 3: CAPITAL COST (EEC) -20%

Capitalization Summary				Basis	
ISBL EEC	MM	7.44		Interest Rate	10%
Royalty	MM	.03		Tax Rate	33%
Interest on Capital, 1 yr.	MM	.75		100% Equity	
		======		Constant Dollars	
Total Capital	MM	8.22			

Income Summary

Case 3: Feed = $200/MT	IRR = 5.0%	IRR = 10.0%	IRR = 15.0%	IRR = 20.0%
Gross Margin	$3.23 MM per yr	$3.65 MM per yr	$4.14 MM per yr	$4.68 MM per yr
Variable Costs	$.28 " " "	$.28 " " "	$.28 " " "	$.28 " " "
Fixed Expenses	$2.19 " " "	$2.19 " " "	$2.19 " " "	$2.19 " " "
ISBL Depreciation	$.74 " " "	$.74 " " "	$.74 " " "	$.74 " " "
Total Pretax Income yrs 1-10	$.01 MM per yr	$.43 MM per yr	$.92 MM per yr	$1.46 MM per yr
Total Aftax Income yrs 1-10	$.01 " " "	$.29 " " "	$.62 " " "	$.98 " " "
Cash Flow yrs 1-10	$.75 " " "	$1.03 " " "	$1.36 " " "	$1.72 " " "
Total Pretax Income yrs 11-20	$.76 MM per yr	$1.18 MM per yr	$1.66 MM per yr	$2.20 MM per yr
Total Aftax Income yrs 11-20	$.51 " " "	$.79 " " "	$1.12 " " "	$1.48 " " "
Cash Flow yrs 11-20	$.51 " " "	$.79 " " "	$1.12 " " "	$1.48 " " "

Gross Margin Calculations
Case 3: Feed=$200 per MT

			IRR = 5.0%		IRR = 10.0%		IRR = 15.0%		IRR = 20.0%	
	lb/hr	MTA	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr
Feedstock	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
Coal Naphtha	8,574	31,113	200	6.22	200	6.22	200	6.22	200	6.22
M.U. Hydrogen	1,631	5,918	232	1.37	232	1.37	232	1.37	232	1.37
	=======	=======	=======	=======	=======	=======	=======	=======	=======	=======
Totals	10,205	37,031		7.60		7.60		7.60		7.60
Products										
Fuel Gas	1,436	5,211	100	.52	100	.52	100	.52	100	.52
LPG	743	2,696	140	.38	140	.38	140	.38	140	.38
Light Product	1,305	4,736	130	.62	130	.62	130	.62	130	.62
Endothermic Fuel	5,881	21,341	416.6	8.88	436.2	9.31	459.1	9.80	484.4	10.34
Heavy Product	605	2,195	144	.32	144	.32	144	.32	144	.32
Waste	235	853	122	.10	122	.10	122	.10	122	.10
	=======	=======	=======	=======	=======	=======	=======	=======	=======	=======
Totals	10,205	37,031		10.82		11.24		11.73		12.27
Gross Margin				$3.23 MM/yr		$3.65 MM/yr		$4.14 MM/yr		$4.68 MM/yr

ENDOTHERMIC FUELS PRODUCTION -- ECONOMIC EVALUATION
SENSITIVITY CASE 3: CAPITAL COST (EEC) -20%

Capitalization Summary

ISBL EEC	MM	7.44
Royalty	MM	.03
Interest on Capital, 1 yr.	MM	.75
		======
Total Capital	MM	8.22

Basis

Interest Rate 10%
Tax Rate 33%
100% Equity
Constant Dollars

Income Summary

Case 4: Feed = $300/MT		IRR = 5.0%	IRR = 10.0%	IRR = 15.0%	IRR = 20.0%
Gross Margin		$3.23 MM per yr	$3.65 MM per yr	$4.14 MM per yr	$4.67 MM per yr
Variable Costs		$.28 " " "	$.28 " " "	$.28 " " "	$.28 " " "
Fixed Expenses		$2.19 " " "	$2.19 " " "	$2.19 " " "	$2.19 " " "
ISBL Depreciation		$.74 " " "	$.74 " " "	$.74 " " "	$.74 " " "
Total Pretax Income	yrs 1-10	$.01 MM per yr	$.43 MM per yr	$.92 MM per yr	$1.46 MM per yr
Total Aftax Income	yrs 1-10	$.01 " " "	$.29 " " "	$.62 " " "	$.98 " " "
Cash Flow	yrs 1-10	$.75 " " "	$1.03 " " "	$1.36 " " "	$1.72 " " "
Total Pretax Income	yrs 11-20	$.76 MM per yr	$1.18 MM per yr	$1.66 MM per yr	$2.20 MM per yr
Total Aftax Income	yrs 11-20	$.51 " " "	$.79 " " "	$1.12 " " "	$1.48 " " "
Cash Flow	yrs 11-20	$.51 " " "	$.79 " " "	$1.12 " " "	$1.48 " " "

Gross Margin Calculations

Case 4: Feed=$300 per MT

			IRR = 5.0%		IRR = 10.0%		IRR = 15.0%		IRR = 20.0%	
	lb/hr	MTA	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr
Feedstock										
Coal Naphtha	8,574	31,113	300	9.33	300	9.33	300	9.33	300	9.33
M.U. Hydrogen	1,631	5,918	232	1.37	232	1.37	232	1.37	232	1.37
Totals	10,205	37,031		10.71		10.71		10.71		10.71
Products										
Fuel Gas	1,436	5,211	100	.52	100	.52	100	.52	100	.52
LPG	743	2,696	140	.38	140	.38	140	.38	140	.38
Light Product	1,305	4,736	130	.62	130	.62	130	.62	130	.62
Endothermic Fuel	5,881	21,341	562.4	12.00	582.0	12.42	604.9	12.91	630.1	13.45
Heavy Product	605	2,195	144	.32	144	.32	144	.32	144	.32
Waste	235	853	122	.10	122	.10	122	.10	122	.10
Totals	10,205	37,031		13.94		14.35		14.84		15.38
Gross Margin				$3.23 MM/yr		$3.65 MM/yr		$4.14 MM/yr		$4.67 MM/yr

ENDOTHERMIC FUELS PRODUCTION -- ECONOMIC EVALUATION

SENSITIVITY CASE 4: VARIABLE COST +10% & BY-PRODUCT CREDITS -10%

Capitalization Summary

ISBL EEC	MM	9.30
Royalty	MM	.03
Interest on Capital, 1 yr.	MM	.93
		======
Total Capital	MM	10.26

Basis

Interest Rate 10%
Tax Rate 33%
100% Equity
Constant Dollars

Income Summary

Case 1: Feed = $0/MT	IRR = 5.0%	IRR = 10.0%	IRR = 15.0%	IRR = 20.0%
Gross Margin	$3.45 MM per yr	$3.97 MM per yr	$4.58 MM per yr	$5.25 MM per yr
Variable Costs	$.31 " " "	$.31 " " "	$.31 " " "	$.31 " " "
Fixed Expenses	$2.19 " " "	$2.19 " " "	$2.19 " " "	$2.19 " " "
ISBL Depreciation	$.93 " " "	$.93 " " "	$.93 " " "	$.93 " " "
Total Pretax Income yrs 1-10	$.02 MM per yr	$.54 MM per yr	$1.15 MM per yr	$1.82 MM per yr
Total Aftax Income yrs 1-10	$.01 " " "	$.36 " " "	$.77 " " "	$1.22 " " "
Cash Flow yrs 1-10	$.94 " " "	$1.29 " " "	$1.70 " " "	$2.15 " " "
Total Pretax Income yrs 11-20	$.95 MM per yr	$1.47 MM per yr	$2.08 MM per yr	$2.75 MM per yr
Total Aftax Income yrs 11-20	$.63 " " "	$.98 " " "	$1.39 " " "	$1.84 " " "
Cash Flow yrs 11-20	$.63 " " "	$.98 " " "	$1.39 " " "	$1.84 " " "

Gross Margin Calculations

Case 1 Feed= $0 per MT

			IRR = 5.0%		IRR = 10.0%		IRR = 15.0%		IRR = 20.0%	
	lb/hr	MTA	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr
Feedstock	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
Coal Naphtha	8,574	31,113	0	0	0	0	0	0	0	0
H.U. Hydrogen	1,631	5,918	232	1.37	232	1.37	232	1.37	232	1.37
	=======	=======	=======	=======	=======	=======	=======	=======	=======	=======
Totals	10,205	37,031		1.37		1.37		1.37		1.37
Products										
Fuel Gas	1,436	5,211	100.0	.52	100.0	.52	100.0	.52	100.0	.52
LPG	743	2,696	140.0	.38	140.0	.38	140.0	.38	140.0	.38
Light Product	1,305	4,736	117.0	.55	117.0	.55	117.0	.55	117.0	.55
Endothermic Fuel	5,881	21,341	140.0	2.99	164.5	3.51	193.2	4.12	224.6	4.79
Heavy Product	605	2,195	129.6	.28	129.6	.28	129.6	.28	129.6	.28
Waste	235	853	100.8	.09	100.8	.09	100.8	.09	100.8	.09
	=======	=======	=======	=======	=======	=======	=======	=======	=======	=======
Totals	10,205	37,031		4.82		5.34		5.95		6.62
Gross Margin				$3.45 MM/yr		$3.97 MM/yr		$4.58 MM/yr		$5.25 MM/yr

ENDOTHERMIC FUELS PRODUCTION -- ECONOMIC EVALUATION
SENSITIVITY CASE 4: VARIABLE COST +10% & BY-PRODUCT CREDITS -10%

Capitalization Summary

ISBL EEC	MM	9.30
Royalty	MM	.03
Interest on Capital, 1 yr.	MM	.93
		======
Total Capital	MM	10.26

Basis

Interest Rate 10%
Tax Rate 33%
100% Equity
Constant Dollars

Income Summary

Case 2 Feed = $100/MT	IRR = 5.0%	IRR = 10.0%	IRR = 15.0%	IRR = 20.0%
Gross Margin	$3.45 MM per yr	$3.97 MM per yr	$4.58 MM per yr	$5.25 MM per yr
Variable Costs	$.31 " " "	$.31 " " "	$.31 " " "	$.31 " " "
Fixed Expenses	$2.19 " " "	$2.19 " " "	$2.19 " " "	$2.19 " " "
ISBL Depreciation	$.93 " " "	$.93 " " "	$.93 " " "	$.93 " " "
Total Pretax Income yrs 1-10	$.02 MM per yr	$.54 MM per yr	$1.15 MM per yr	$1.82 MM per yr
Total Aftax Income yrs 1-10	$.01 " " "	$.36 " " "	$.77 " " "	$1.22 " " "
Cash Flow yrs 1-10	$.94 " " "	$1.29 " " "	$1.70 " " "	$2.15 " " "
Total Pretax Income yrs 11-20	$.95 MM per yr	$1.47 MM per yr	$2.08 MM per yr	$2.75 MM per yr
Total Aftax Income yrs 11-20	$.63 " " "	$.98 " " "	$1.39 " " "	$1.84 " " "
Cash Flow yrs 11-20	$.63 " " "	$.98 " " "	$1.39 " " "	$1.84 " " "

Gross Margin Calculations
Case 2 Feed=$100 per MT

			IRR = 5.0%		IRR = 10.0%		IRR = 15.0%		IRR = 20.0%	
	lb/hr	MTA	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr
Feedstock										
Coal Naphtha	8,574	31,113	100	3.11	100	3.11	100	3.11	100	3.11
M.U Hydrogen	1,631	5,918	232	1.37	232	1.37	232	1.37	232	1.37
Totals	10,205	37,031		4.48		4.48		4.48		4.48
Products										
Fuel Gas	1,436	5,211	100.0	.52	100.0	.52	100.0	.52	100.0	.52
LPG	743	2,696	140.0	.38	140.0	.38	140.0	.38	140.0	.38
Light Product	1,305	4,736	117.0	.55	117.0	.55	117.0	.55	117.0	.55
Endothermic Fuel	5,881	21,341	285.8	6.10	310.3	6.62	339.0	7.23	370.4	7.90
Heavy Product	605	2,195	129.6	.28	129.6	.28	129.6	.28	129.6	.28
Waste	235	853	100.0	.00	100.0	.00	100.0	.00	100.0	.00
Totals	10,205	37,031		7.93		8.45		9.07		9.74
Gross Margin				$3.45 MM/yr		$3.97 MM/yr		$4.58 MM/yr		$5.25 MM/yr

ENDOTHERMIC FUELS PRODUCTION -- ECONOMIC EVALUATION

SENSITIVITY CASE 4: VARIABLE COST +10% & BY-PRODUCT CREDITS -10%

Capitalization Summary		
ISBL EEC	MM	9.30
Royalty	MM	.03
Interest on Capital, 1 yr.	MM	.93
		======
Total Capital	MM	10.26

Basis

Interest Rate 10%
Tax Rate 33%
100% Equity
Constant Dollars

Income Summary

Case 3: Feed = $200/MT	IRR = 5.0%	IRR = 10.0%	IRR = 15.0%	IRR = 20.0%
Gross Margin	$3.45 MM per yr	$3.97 MM per yr	$4.58 MM per yr	$5.25 MM per yr
Variable Costs	$.31 " " "	$.31 " " "	$.31 " " "	$.31 " " "
Fixed Expenses	$2.19 " " "	$2.19 " " "	$2.19 " " "	$2.19 " " "
ISBL Depreciation	$.93 " " "	$.93 " " "	$.93 " " "	$.93 " " "
Total Pretax Income yrs 1-10	$.02 MM per yr	$.54 MM per yr	$1.15 MM per yr	$1.82 MM per yr
Total Aftax Income yrs 1-10	$.01 " " "	$.36 " " "	$.77 " " "	$1.22 " " "
Cash Flow yrs 1-10	$.94 " " "	$1.29 " " "	$1.70 " " "	$2.15 " " "
Total Pretax Income yrs 11-20	$.95 MM per yr	$1.47 MM per yr	$2.08 MM per yr	$2.75 MM per yr
Total Aftax Income yrs 11-20	$.63 " " "	$.98 " " "	$1.39 " " "	$1.84 " " "
Cash Flow yrs 11-20	$.63 " " "	$.98 " " "	$1.39 " " "	$1.84 " " "

Gross Margin Calculations

Case 3: Feed=$200 per MT

			IRR = 5.0%		IRR = 10.0%		IRR = 15.0%		IRR = 20.0%	
	lb/hr	MTA	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr
Feedstock										
Coal Naphtha	8,574	31,113	200	6.22	200	6.22	200	6.22	200	6.22
H.U. Hydrogen	1,631	5,918	232	1.37	232	1.37	232	1.37	232	1.37
Totals	10,205	37,031		7.60		7.60		7.60		7.60
Products										
Fuel Gas	1,436	5,211	100.0	.52	100.0	.52	100.0	.52	100.0	.52
LPG	743	2,696	140.0	.38	140.0	.38	140.0	.38	140.0	.38
Light Product	1,305	4,736	117.0	.55	117.0	.55	117.0	.55	117.0	.55
Endothermic Fuel	5,881	21,341	431.6	9.21	456.1	9.73	484.8	10.35	516.2	11.02
Heavy Product	605	2,195	129.6	.28	129.6	.28	129.6	.28	129.6	.28
Waste	235	853	108.8	.09	108.8	.09	108.8	.09	108.8	.09
Totals	10,205	37,031		11.04		11.56		12.18		12.85
Gross Margin				$3.45 MM/yr		$3.97 MM/yr		$4.58 MM/yr		$5.25 MM/yr

ENDOTHERMIC FUELS PRODUCTION -- ECONOMIC EVALUATION
SENSITIVITY CASE 4: VARIABLE COST +10% & BY-PRODUCT CREDITS -10%

Capitalization Summary

ISBL EEC	MM	9.30
Royalty	MM	.03
Interest on Capital, 1 yr.	MM	.93
		======
Total Capital	MM	10 26

Basis

Interest Rate 10%
Tax Rate 33%
100% Equity
Constant Dollars

Income Summary

Case 4: Feed = $300/MT	IRR = 5.0%	IRR = 10.0%	IRR = 15.0%	IRR = 20.0%
Gross Margin	$3.45 MM per yr	$3.97 MM per yr	$4.58 MM per yr	$5.25 MM per yr
Variable Costs	$.31 " " "	$.31 " " "	$.31 " " "	$.31 " " "
Fixed Expenses	$2.19 " " "	$2.19 " " "	$2.19 " " "	$2.19 " " "
ISBL Depreciation	$.93 " " "	$.93 " " "	$.93 " " "	$.93 " " "
Total Pretax Income yrs 1-10	$.02 MM per yr	$.54 MM per yr	$1.15 MM per yr	$1.82 MM per yr
Total Aftax Income yrs 1-10	$.01 " " "	$.36 " " "	$.77 " " "	$1.22 " " "
Cash Flow yrs 1-10	$.94 " " "	$1.29 " " "	$1.70 " " "	$2.15 " " "
Total Pretax Income yrs 11-20	$.95 MM per yr	$1.47 MM per yr	$2.08 MM per yr	$2.75 MM per yr
Total Aftax Income yrs 11-20	$ 63 " " "	$.98 " " "	$1.39 " " "	$1.84 " " "
Cash Flow yrs 11-20	$.63 " " "	$.98 " " "	$1.39 " " "	$1.84 " " "

Gross Margin Calculations

Case 4: Feed=$300 per MT

			IRR = 5.0%		IRR = 10.0%		IRR = 15.0%		IRR = 20.0%	
	lb/hr	MTA	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr
Feedstock										
Coal Naphtha	8,574	31,113	300	9.33	300	9.33	300	9.33	300	9.33
M.U. Hydrogen	1,631	5,918	232	1.37	232	1.37	232	1.37	232	1.37
Totals	10,205	37,031		10.71		10.71		10.71		10.71
Products										
Fuel Gas	1,436	5,211	100.0	.52	100.0	.52	100.0	.52	100.0	.52
LPG	743	2,696	140.0	.38	140.0	.38	140.0	.38	140.0	.38
Light Product	1,305	4,736	117.0	.55	117.0	.55	117.0	.55	117.0	.55
Endothermic Fuel	5,881	21,341	577.4	12.32	601.9	12.84	630.5	13.46	662.0	14.13
Heavy Product	605	2,195	129.6	.28	129.6	.28	129.6	.28	129.6	.28
Waste	235	853	100.8	.09	100.8	.09	100.8	.09	100.8	.09
Totals	10,205	37,031		14.15		14.68		15.29		15.96
Gross Margin				$3.45 MM/yr		$3.97 MM/yr		$4.58 MM/yr		$5.25 MM/yr

ENDOTHERMIC FUELS PRODUCTION -- ECONOMIC EVALUATION
SENSITIVITY CASE 5: VARIABLE COST +20% & BY-PRODUCT CREDITS -20%

Capitalization Summary

ISBL EEC	MM	9.30
Royalty	MM	.03
Interest on Capital, 1 yr.	MM	.93
		======
Total Capital	MM	10.26

Basis

Interest Rate 10%
Tax Rate 33%
100% Equity
Constant Dollars

Income Summary

Case 1: Feed = $0/MT		IRR = 5.0%	IRR = 10.0%	IRR = 15.0%	IRR = 20.0%
Gross Margin		$3.47 MM per yr	$4.00 MM per yr	$4.61 MM per yr	$5.28 MM per yr
Variable Costs		$.34 " " "	$.34 " " "	$.34 " " "	$.34 " " "
Fixed Expenses		$2.19 " " "	$2.19 " " "	$2.19 " " "	$2.19 " " "
ISBL Depreciation		$.93 " " "	$.93 " " "	$.93 " " "	$.93 " " "
Total Pretax Income	yrs 1-10	$.02 MM per yr	$.54 MM per yr	$1.15 MM per yr	$1.82 MM per yr
Total Aftax Income	yrs 1-10	$.01 " " "	$.36 " " "	$.77 " " "	$1.22 " " "
Cash Flow	yrs 1-10	$.94 " " "	$1.29 " " "	$1.70 " " "	$2.15 " " "
Total Pretax Income	yrs 11-20	$.95 MM per yr	$1.47 MM per yr	$2.08 MM per yr	$2.75 MM per yr
Total Aftax Income	yrs 11-20	$.63 " " "	$.98 " " "	$1.39 " " "	$1.84 " " "
Cash Flow	yrs 11-20	$.63 " " "	$.98 " " "	$1.39 " " "	$1.84 " " "

Gross Margin Calculations

Case 1: Feed= $0 per MT

			IRR = 5.0%		IRR = 10.0%		IRR = 15.0%		IRR = 20.0%	
	lb/hr	MTA	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr
Feedstock										
Coal Naphtha	8,574	31,113	0	0	0	0	0	0	0	0
M.U. Hydrogen	1,631	5,918	232	1.37	232	1.37	232	1.37	232	1.37
Totals	10,205	37,031		1.37		1.37		1.37		1.37
Products										
Fuel Gas	1,436	5,211	100.0	.52	100.0	.52	100.0	.52	100.0	.52
LPG	743	2,696	140.0	.38	140.0	.38	140.0	.38	140.0	.38
Light Product	1,305	4,736	104.0	.49	104.0	.49	104.0	.49	104.0	.49
Endothermic Fuel	5,881	21,341	146.2	3.12	170.7	3.64	199.4	4.26	230.8	4.93
Heavy Product	605	2,195	115.2	.25	115.2	.25	115.2	.25	115.2	.25
Waste	235	853	97.6	.08	97.6	.08	97.6	.08	97.6	.08
Totals	10,205	37,031		4.85		5.37		5.98		6.65
Gross Margin				$3.47 MM/yr		$4.00 MM/yr		$4.61 MM/yr		$5.28 MM/yr

ENDOTHERMIC FUELS PRODUCTION -- ECONOMIC EVALUATION
SENSITIVITY CASE 5: VARIABLE COST +20% & BY-PRODUCT CREDITS -20%

Capitalization Summary

ISBL EEC	MM	9.30
Royalty	MM	.03
Interest on Capital, 1 yr.	MM	.93
Total Capital	MM	10.26

Basis

Interest Rate 10%
Tax Rate 33%
100% Equity
Constant Dollars

Income Summary

Case 2: Feed = $100/MT	IRR = 5.0%	IRR = 10.0%	IRR = 15.0%	IRR = 20 0%
Gross Margin	$3.47 MM per yr	$4.00 MM per yr	$4.61 MM per yr	$5.28 MM per yr
Variable Costs	$.34 " " "	$.34 " " "	$.34 " " "	$.34 " " "
Fixed Expenses	$2.19 " " "	$2.19 " " "	$2.19 " " "	$2.19 " " "
ISBL Depreciation	$.93 " " "	$.93 " " "	$.93 " " "	$.93 " " "
Total Pretax Income yrs 1-10	$.02 MM per yr	$.54 MM per yr	$1.15 MM per yr	$1.82 MM per yr
Total Aftax Income yrs 1-10	$.01 " " "	$.36 " " "	$.77 " " "	$1.22 " " "
Cash Flow yrs 1-10	$.94 " " "	$1.29 " " "	$1.70 " " "	$2.15 " " "
Total Pretax Income yrs 11-20	$.95 MM per yr	$1.47 MM per yr	$2.08 MM per yr	$2.75 MM per yr
Total Aftax Income yrs 11-20	$.63 " " "	$.98 " " "	$1.39 " " "	$1.84 " " "
Cash Flow yrs 11-20	$.63 " " "	$.98 " " "	$1.39 " " "	$1.84 " " "

Gross Margin Calculations
Case 2: Feed=$100 per MT

			IRR = 5.0%		IRR = 10.0%		IRR = 15.0%		IRR = 20.0%	
	lb/hr	MTA	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr
Feedstock										
Coal Naphtha	8,574	31,113	100	3.11	100	3.11	100	3.11	100	3.11
N.U. Hydrogen	1,831	5,918	232	1.37	232	1.37	232	1.37	232	1.37
Totals	10,205	37,031		4.48		4.48		4.48		4.48
Products										
Fuel Gas	1,436	5,211	100.0	.52	100.0	.52	100.0	.52	100.0	.52
LPG	743	2,696	140.0	.38	140.0	.38	140.0	.38	140.0	.38
Light Product	1,305	4,736	104.0	.49	104.0	.49	104.0	.49	104.0	.49
Endothermic Fuel	5,881	21,341	292.0	6.23	316.5	6.75	345.1	7.36	376.6	8.04
Heavy Product	605	2,195	115.2	.25	115.2	.25	115.2	.25	115.2	.25
Waste	235	853	97.6	.08	97.6	.08	97.6	.08	97.6	.08
Totals	10,205	37,031		7.96		8.48		9.08		9.76
Gross Margin				$3.47 MM/yr		$4.00 MM/yr		$4.61 MM/yr		$5.28 MM/yr

ENDOTHERMIC FUELS PRODUCTION -- ECONOMIC EVALUATION
SENSITIVITY CASE 5: VARIABLE COST +20% & BY-PRODUCT CREDITS -20%

Capitalization Summary

ISBL EEC	MM	9.30
Royalty	MM	.03
Interest on Capital, 1 yr.	MM	.93
		======
Total Capital	MM	10.26

Basis

Interest Rate 10%
Tax Rate 33%
100% Equity
Constant Dollars

Income Summary

Case 3: Feed = $200/MT	IRR = 5.0%	IRR = 10.0%	IRR = 15.0%	IRR = 20.0%
Gross Margin	$3.47 MM per yr	$4.00 MM per yr	$4.61 MM per yr	$5.28 MM per yr
Variable Costs	$.34 " " "	$.34 " " "	$.34 " " "	$.34 " " "
Fixed Expenses	$2.19 " " "	$2.19 " " "	$2.19 " " "	$2.19 " " "
ISBL Depreciation	$.93 " " "	$.93 " " "	$.93 " " "	$.93 " " "
Total Pretax Income yrs 1-10	$.02 MM per yr	$.54 MM per yr	$1.15 MM per yr	$1.82 MM per yr
Total Aftax Income yrs 1-10	$.01 " " "	$.36 " " "	$.77 " " "	$1.22 " " "
Cash Flow yrs 1-10	$.94 " " "	$1.29 " " "	$1.70 " " "	$2.15 " " "
Total Pretax Income yrs 11-20	$.95 MM per yr	$1.47 MM per yr	$2.08 MM per yr	$2.75 MM per yr
Total Aftax Income yrs 11-20	$.63 " " "	$.98 " " "	$1.39 " " "	$1.84 " " "
Cash Flow yrs 11-20	$.63 " " "	$.98 " " "	$1.39 " " "	$1.84 " " "

Gross Margin Calculations
Case 3: Feed=$200 per MT

			IRR = 5.0%		IRR = 10.0%		IRR = 15.0%		IRR = 20.0%	
	lb/hr	MTA	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr
Feedstock										
Coal Naphtha	8,574	31,113	200	6.22	200	6.22	200	6.22	200	6.22
H.U. Hydrogen	1,631	5,918	232	1.37	232	1.37	232	1.37	232	1.37
Totals	10,205	37,031		7.60		7.60		7.60		7.60
Products										
Fuel Gas	1,436	5,211	100.0	.52	100.0	.52	100.0	.52	100.0	.52
LPG	743	2,696	140.0	.38	140.0	.38	140.0	.38	140.0	.38
Light Product	1,305	4,736	104.0	.49	104.0	.49	104.0	.49	104.0	.49
Endothermic Fuel	5,881	21,341	437.6	9.34	462.3	9.87	490.9	10.48	522.4	11.15
Heavy Product	605	2,195	115.2	.25	115.2	.25	115.2	.25	115.2	.25
Waste	235	853	97.6	.08	97.6	.08	97.6	.08	97.6	.08
Totals	10,205	37,031		11.07		11.60		12.20		12.88
Gross Margin				$3.47 MM/yr		$4.00 MM/yr		$4.61 MM/yr		$5.28 MM/yr

ENDOTHERMIC FUELS PRODUCTION — ECONOMIC EVALUATION
SENSITIVITY CASE 5: VARIABLE COST +20% & BY-PRODUCT CREDITS -20%

Capitalization Summary

ISBL EEC	MM	9.30
Royalty	MM	.03
Interest on Capital, 1 yr.	MM	.93
		======
Total Capital	MM	10.26

Basis

Interest Rate 10%
Tax Rate 33%
100% Equity
Constant Dollars

Income Summary

Case 4: Feed = $300/MT	IRR = 5.0%	IRR = 10.0%	IRR = 15.0%	IRR = 20.0%
Gross Margin	$3.47 MM per yr	$4.00 MM per yr	$4.61 MM per yr	$5.28 MM per yr
Variable Costs	$.34 " " "	$.34 " " "	$.34 " " "	$.34 " " "
Fixed Expenses	$2.19 " " "	$2 19 " " "	$2.19 " " "	$2.19 " " "
ISBL Depreciation	$.93 " " "	$.93 " " "	$.93 " " "	$.93 " " "
Total Pretax Income yrs 1-10	$.02 MM per yr	$.54 MM per yr	$1.15 MM per yr	$1.82 MM per yr
Total Aftax Income yrs 1-10	$.01 " " "	$.36 " " "	$.77 " " "	$1.22 " " "
Cash Flow yrs 1-10	$.94 " " "	$1.29 " " "	$1.70 " " "	$2.15 " " "
Total Pretax Income yrs 11-20	$.95 MM per yr	$1.47 MM per yr	$2.08 MM per yr	$2.75 MM per yr
Total Aftax Income yrs 11-20	$.63 " " "	$.98 " " "	$1.39 " " "	$1.84 " " "
Cash Flow yrs 11-20	$.63 " " "	$.98 " " "	$1.39 " " "	$1.84 " " "

Gross Margin Calculations

Case 4. Feed=$300 per MT

			IRR = 5.0%		IRR = 10.0%		IRR = 15.0%		IRR = 20.0%	
	lb/hr	MTA	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr
Feedstock	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
Coal Naphtha	8,574	31,113	300	9.33	300	9.33	300	9.33	300	9.33
H.U. Hydrogen	1,631	5,918	232	1.37	232	1.37	232	1.37	232	1.37
	=======	=======	=======	=======	=======	=======	=======	=======	=======	=======
Totals	10,205	37,031		10.71		10.71		10.71		10.71
Products										
Fuel Gas	1,436	5,211	100.0	.52	100.0	.52	100.0	.52	100.0	.52
LPG	743	2,696	140.0	.38	140.0	.38	140.0	.38	140.0	.38
Light Product	1,305	4,736	104.0	.49	104.0	.49	104.0	.49	104.0	.49
Endothermic Fuel	5,881	21,341	583.6	12.45	608.1	12.98	636.7	13.59	668.2	14.26
Heavy Product	605	2,195	115.2	.25	115.2	.25	115.2	.25	115.2	.25
Waste	235	853	97.6	.08	97.6	.08	97.6	.08	97.6	.08
	=======	=======	=======	=======	=======	=======	=======	=======	=======	=======
Totals	10,205	37,031		14.18		14.70		15.31		15.99
Gross Margin				$3.47 MM/yr		$4.00 MM/yr		$4.61 MM/yr		$5.28 MM/yr

ENDOTHERMIC FUELS PRODUCTION -- ECONOMIC EVALUATION
SENSITIVITY CASE 6: VARIABLE COST -10% & BY-PRODUCT CREDITS +10%

Capitalization Summary			Basis
ISBL EEC	MM	9.30	Interest Rate 10%
Royalty	MM	.03	Tax Rate 33%
Interest on Capital, 1 yr.	MM	.93	100% Equity
		======	Constant Dollars
Total Capital	MM	10.26	

Income Summary

Case 1: Feed = $0/MT	IRR = 5.0%	IRR = 10.0%	IRR = 15.0%	IRR = 20.0%
Gross Margin	$3.39 MM per yr	$3.91 MM per yr	$4.52 MM per yr	$5.19 MM per yr
Variable Costs	$.26 " " "	$.26 " " "	$.26 " " "	$.26 " " "
Fixed Expenses	$2.19 " " "	$2.19 " " "	$2.19 " " "	$2.19 " " "
ISBL Depreciation	$.93 " " "	$.93 " " "	$.93 " " "	$.93 " " "
Total Pretax Income yrs 1-10	$.01 MM per yr	$.54 MM per yr	$1.15 MM per yr	$1.82 MM per yr
Total Aftax Income yrs 1-10	$.01 " " "	$.36 " " "	$.77 " " "	$1.22 " " "
Cash Flow yrs 1-10	$.94 " " "	$1.29 " " "	$1.70 " " "	$2.15 " " "
Total Pretax Income yrs 11-20	$.94 MM per yr	$1.47 MM per yr	$2.08 MM per yr	$2.75 MM per yr
Total Aftax Income yrs 11-20	$.63 " " "	$.98 " " "	$1.39 " " "	$1.84 " " "
Cash Flow yrs 11-20	$.63 " " "	$.98 " " "	$1.39 " " "	$1.84 " " "

Gross Margin Calculations

Case I: Feed= $0 per MT

			IRR = 5.0%		IRR = 10.0%		IRR = 15.0%		IRR = 20.0%	
	lb/hr	MTA	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr
Feedstock	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
Coal Naphtha	8,574	31,113	0	0	0	0	0	0	0	0
N.U. Hydrogen	1,631	5,918	232	1.37	232	1.37	232	1.37	232	1.37
	=======	=======	=======	=======	=======	=======	=======	=======	=======	=======
Totals	10,205	37,031		1.37		1.37		1.37		1.37
Products										
Fuel Gas	1,436	5,211	100.0	.52	100.0	.52	100.0	.52	100.0	.52
LPG	743	2,696	140.0	.38	140.0	.38	140.0	.38	140.0	.38
Light Product	1,305	4,736	143.0	.68	143.0	.68	143.0	.68	143.0	.68
Endothermic Fuel	5,881	21,341	127.6	2.72	152.2	3.25	180.8	3.86	212.3	4.53
Heavy Product	605	2,195	158.4	.35	158.4	.35	158.4	.35	158.4	.35
Waste	235	853	134.2	.11	134.2	.11	134.2	.11	134.2	.11
	=======	=======	=======	=======	=======	=======	=======	=======	=======	=======
Totals	10,205	37,031		4.76		5.29		5.90		6.57
Gross Margin				$3.39 MM/yr		$3.91 MM/yr		$4.52 MM/yr		$5.20 MM/yr

ENDOTHERMIC FUELS PRODUCTION -- ECONOMIC EVALUATION
SENSITIVITY CASE 6: VARIABLE COST -10% & BY-PRODUCT CREDITS +10%

Capitalization Summary				Basis
ISBL EEC	MM	9.30		Interest Rate 10%
Royalty	MM	.03		Tax Rate 33%
Interest on Capital, 1 yr.	MM	.93		100% Equity
		======		Constant Dollars
Total Capital	MM	10.26		

Income Summary

Case 2: Feed = $100/MT		IRR = 5.0%	IRR = 10.0%	IRR = 15.0%	IRR = 20.0%
Gross Margin		$3.39 MM per yr	$3.91 MM per yr	$4.52 MM per yr	$5.19 MM per yr
Variable Costs		$.26 " " "	$.26 " " "	$.26 " " "	$.26 " " "
Fixed Expenses		$2.19 " " "	$2.19 " " "	$2.19 " " "	$2.19 " " "
ISBL Depreciation		$.93 " " "	$.93 " " "	$.93 " " "	$.93 " " "
Total Pretax Income	yrs 1-10	$.01 MM per yr	$.54 MM per yr	$1.15 MM per yr	$1.82 MM per yr
Total Aftax Income	yrs 1-10	$.01 " " "	$.36 " " "	$.77 " " "	$1.22 " " "
Cash Flow	yrs 1-10	$.94 " " "	$1.29 " " "	$1.70 " " "	$2.15 " " "
Total Pretax Income	yrs 11-20	$.94 MM per yr	$1.47 MM per yr	$2.08 MM per yr	$2.75 MM per yr
Total Aftax Income	yrs 11-20	$.63 " " "	$.98 " " "	$1.39 " " "	$1.84 " " "
Cash Flow	yrs 11-20	$.63 " " "	$.98 " " "	$1.39 " " "	$1.84 " " "

Gross Margin Calculations
Case 2: Feed=$100 per MT

			IRR = 5.0%		IRR = 10.0%		IRR = 15.0%		IRR = 20.0%	
	lb/hr	MTA	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr
Feedstock										
Coal Naphtha	8,574	31,113	100	3.11	100	3.11	100	3.11	100	3.11
H.U. Hydrogen	1,631	5,918	232	1.37	232	1.37	232	1.37	232	1.37
Totals	10,205	37,031		4.48		4.48		4.48		4.48
Products										
Fuel Gas	1,436	5,211	100.0	.52	100.0	.52	100.0	.52	100.0	.52
LPG	743	2,696	140.0	.38	140.0	.38	140.0	.38	140.0	.38
Light Product	1,305	4,736	143.0	.68	143.0	.68	143.0	.68	143.0	.68
Endothermic Fuel	5,881	21,341	273.4	5.83	298.0	6.36	326.6	6.97	358.0	7.64
Heavy Product	605	2,195	158.4	.35	158.4	.35	158.4	.35	158.4	.35
Waste	235	853	134.2	.11	134.2	.11	134.2	.11	134.2	.11
Totals	10,205	37,031		7.87		8.40		9.01		9.68
Gross Margin				$3.39 MM/yr		$3.91 MM/yr		$4.52 MM/yr		$5.19 MM/yr

ENDOTHERMIC FUELS PRODUCTION -- ECONOMIC EVALUATION
SENSITIVITY CASE 6: VARIABLE COST -10% & BY-PRODUCT CREDITS +10%

Capitalization Summary

ISBL EEC	MM	9.30
Royalty	MM	.03
Interest on Capital, 1 yr.	MM	.93
		======
Total Capital	MM	10.26

Basis

Interest Rate 10%
Tax Rate 33%
100% Equity
Constant Dollars

Income Summary

Case 3: Feed = $200/MT		IRR = 5.0%	IRR = 10.0%	IRR = 15.0%	IRR = 20.0%
Gross Margin		$3.39 MM per yr	$3.91 MM per yr	$4.52 MM per yr	$5.20 MM per yr
Variable Costs		$.26 " " "	$.26 " " "	$.26 " " "	$.26 " " "
Fixed Expenses		$2.19 " " "	$2.19 " " "	$2.19 " " "	$2.19 " " "
ISBL Depreciation		$.93 " " "	$.93 " " "	$.93 " " "	$.93 " " "
Total Pretax Income	yrs 1-10	$.01 MM per yr	$.54 MM per yr	$1.15 MM per yr	$1.82 MM per yr
Total Aftax Income	yrs 1-10	$.01 " " "	$.36 " " "	$.77 " " "	$1.22 " " "
Cash Flow	yrs 1-10	$.94 " " "	$1.29 " " "	$1.70 " " "	$2.15 " " "
Total Pretax Income	yrs 11-20	$.94 MM per yr	$1.47 MM per yr	$2.08 MM per yr	$2.75 MM per yr
Total Aftax Income	yrs 11-20	$.63 " " "	$.98 " " "	$1.39 " " "	$1.84 " " "
Cash Flow	yrs 11-20	$.63 " " "	$.98 " " "	$1.39 " " "	$1.84 " " "

Gross Margin Calculations

Case 3: Feed=$200 per MT

			IRR = 5.0%		IRR = 10.0%		IRR = 15.0%		IRR = 20.0%	
	lb/hr	MTA	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr
Feedstock	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
Coal Naphtha	8,574	31.113	200	6.22	200	6.22	200	6.22	200	6.22
H.U. Hydrogen	1,631	5,918	232	1.37	232	1.37	232	1.37	232	1.37
	=======	=======	=======	=======	=======	=======	=======	=======	=======	=======
Totals	10,205	37,031		7.60		7.60		7.60		7.60
Products										
Fuel Gas	1,436	5,211	100.0	.52	100.0	.52	100.0	.52	100.0	.52
LPG	743	2,696	140.0	.38	140.0	.38	140.0	.38	140.0	.38
Light Product	1,305	4,736	143.0	.68	143.0	.68	143.0	.68	143.0	.68
Endothermic Fuel	5,881	21,341	419.2	8.95	443.7	9.47	472.4	10.08	503.8	10.75
Heavy Product	605	2,195	158.4	.35	158.4	.35	158.4	.35	158.4	.35
Waste	235	853	134.2	.11	134.2	.11	134.2	.11	134.2	.11
	=======	=======	=======	=======	=======	=======	=======	=======	=======	=======
Totals	10,205	37,031		10.98		11.51		12.12		12.79
Gross Margin				$3.39 MM/yr		$3.91 MM/yr		$4.52 MM/yr		$5.19 MM/yr

ENDOTHERMIC FUELS PRODUCTION -- ECONOMIC EVALUATION
SENSITIVITY CASE 6: VARIABLE COST -10% & BY-PRODUCT CREDITS +10%

Capitalization Summary

ISBL EEC	MM	9.30
Royalty	MM	.03
Interest on Capital, 1 yr.	MM	.93
		======
Total Capital	MM	10.26

Basis

Interest Rate 10%
Tax Rate 33%
100% Equity
Constant Dollars

Income Summary

Case 4: Feed = $300/MT	IRR = 5.0%	IRR = 10.0%	IRR = 15.0%	IRR = 20.0%
Gross Margin	$3.39 MM per yr	$3.91 MM per yr	$4.52 MM per yr	$5.19 MM per yr
Variable Costs	$.26 " " "	$.26 " " "	$.26 " " "	$.26 " " "
Fixed Expenses	$2.19 " " "	$2.19 " " "	$2.19 " " "	$2.19 " " "
ISBL Depreciation	$.93 " " "	$.93 " " "	$.93 " " "	$.93 " " "
Total Pretax Income yrs 1-10	$.01 MM per yr	$.54 MM per yr	$1.15 MM per yr	$1.82 MM per yr
Total Aftax Income yrs 1-10	$.01 " " "	$.36 " " "	$.77 " " "	$1.22 " " "
Cash Flow yrs 1-10	$.94 " " "	$1.29 " " "	$1.70 " " "	$2.15 " " "
Total Pretax Income yrs 11-20	$.94 MM per yr	$1.47 MM per yr	$2.08 MM per yr	$2.75 MM per yr
Total Aftax Income yrs 11-20	$.63 " " "	$.98 " " "	$1.39 " " "	$1.84 " " "
Cash Flow yrs 11-20	$.63 " " "	$.98 " " "	$1.39 " " "	$1.84 " " "

Gross Margin Calculations

Case 4: Feed=$300 per MT

			IRR = 5.0%		IRR = 10.0%		IRR = 15.0%		IRR = 20.0%	
	lb/hr	MTA	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr	$/MT	$ MM/yr
Feedstock										
Coal Naphtha	8,574	31,113	300	9.33	300	9.33	300	9.33	300	9.33
M.U. Hydrogen	1,631	5,918	232	1.37	232	1.37	232	1.37	232	1.37
Totals	10,205	37,031		10.71		10.71		10.71		10.71
Products										
Fuel Gas	1,436	5,211	100.0	.52	100.0	.52	100.0	.52	100.0	.52
LPG	743	2,696	140.0	.38	140.0	.38	140.0	.38	140.0	.38
Light Product	1,305	4,736	143.0	.68	143.0	.68	143.0	.68	143.0	.68
Endothermic Fuel	5,881	21,341	565.0	12.06	589.5	12.58	618.2	13.19	649.6	13.86
Heavy Product	605	2,195	158.4	.35	158.4	.35	158.4	.35	158.4	.35
Waste	235	853	134.2	.11	134.2	.11	134.2	.11	134.2	.11
Totals	10,205	37,031		14.10		14.62		15.23		15.90
Gross Margin				$3.39 MM/yr		$3.91 MM/yr		$4.52 MM/yr		$5.19 MM/yr

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